Chapter 4: Environmental Consequences

4.1 Framework for Analysis

4.1.1 Introduction

The figure to the left illustrates the framework used to analyze environmental impacts of Business Plan alternatives. The environmental consequences of the alternatives result, for the most part, from market responses to those alternatives. Market responses are the actions that BPA, its customers and competitors, and end-use consumers take in response to BPA's actions in implementing its Business Plan. Section 4.2 identifies the market responses to the issues identified in chapter 2. Generic environmental impacts are addressed in section 4.3. Section 4.4 sets out the cumulative market responses and environmental impacts of the different alternatives, and section 4.5 does the same for modules. The FEIS projects actions, responses, and impacts to the year 2002, but the relationships are expected to hold true well beyond 2002..

4.1.2 Market Responses

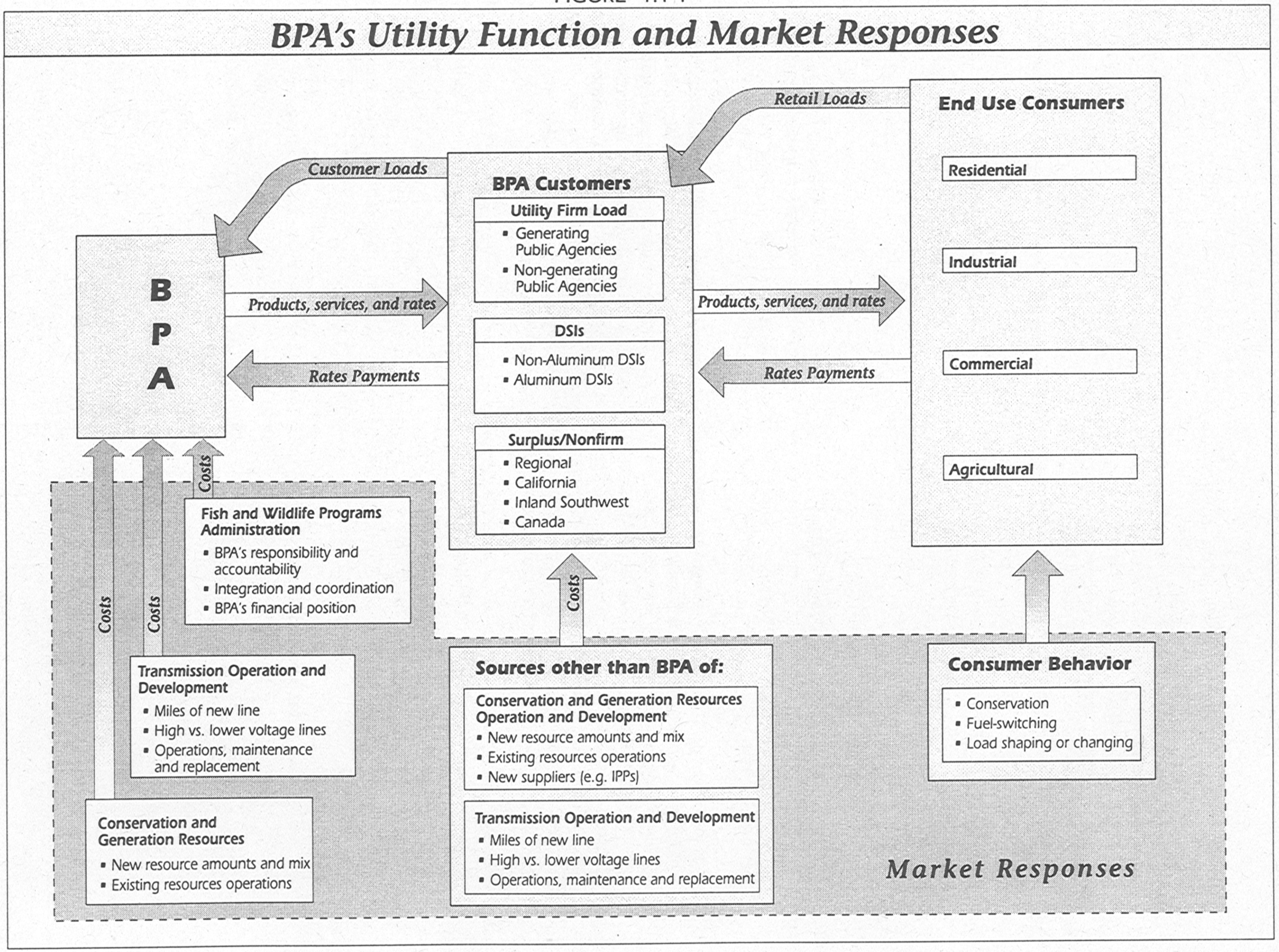
BPA decisions on business direction do not by themselves result in environmental impacts. Impacts also result from the actions in the electric energy industry and among consumers in response to BPA's business decisions. Environmental impacts of the six alternatives can be derived from "market responses" to policy directions or to the treatment of issues under each alternative. For the purpose of this EIS, market responses are sorted into four categories:

1. **RESOURCE DEVELOPMENT**
2. **RESOURCE OPERATIONS**
3. **TRANSMISSION DEVELOPMENT AND OPERATIONS**
4. **CONSUMER BEHAVIOR.**

These market responses include BPA actions and those of customers and suppliers, as these actions are often complementary. With some deviations, the PNW electric utility industry as a whole tends to develop sufficient resources to supply the total expected loads in the region: if BPA develops more resources, other developers will develop fewer, and vice versa. The total regional demand for electric power services will be met by all the actions of BPA and other suppliers, but the balance between them may shift depending on the capabilities, policies, and competitiveness of one or the other.

Figure 4.1-1 illustrates the interaction between BPA and its customers and their end-use consumers.

FIGURE 4.1-1


BPA's Utility Function and Market Responses
Retail Loads
End Use Consumers
Residential
Industrial
Commercial
Agricultural
Customer Loads
BPA Customers
Utility Firm Load
▪ Generating Public Agencies
▪ Non-generating Public Agencies
DSIs
▪ Non-Aluminum DSIs
▪ Aluminum DSIs
Surplus/Nonfirm
▪ Regional
▪ California
▪ Inland Southwest
▪ Canada
B P A
Products, services, and rates
Rates Payments
Products, services, and rates
Rates Payments
Costs
Costs
Costs
Costs
Fish and Wildlife Programs Administration
▪ BPA's responsibility and accountability
▪ Integration and coordination
▪ BPA's financial position
Transmission Operation and Development
▪ Miles of new line
▪ High vs. lower voltage lines
▪ Operations, maintenance and replacement
Conservation and Generation Resources
▪ New resource amounts and mix
▪ Existing resources operations
Sources other than BPA of:
Conservation and Generation Resources Operation and Development
▪ New resource amounts and mix
▪ Existing resources operations
▪ New suppliers (e.g. IPPs)
Transmission Operation and Development
▪ Miles of new line
▪ High vs. lower voltage lines
▪ Operations, maintenance and replacement
Consumer Behavior
▪ Conservation
▪ Fuel-switching
▪ Load shaping or changing
Market Responses

4.1.2.1 Resource Development

Resource development, the most prominent of these market responses, predicts the different amounts or types of resources developed by BPA or its customers in response to various BPA business decisions. BPA business decisions will affect the types of services available from BPA, the price for those services, and other conditions that may be placed on BPA service. These factors, along with the availability of comparable service from
other suppliers, will affect a utility's decision on whether to purchase electric power or services from BPA. The total demand for power services from BPA will define the total amount of additional resources BPA needs to meet its loads. The remaining demand in the region must be met by other suppliers. **Differences in environmental impacts will arise from differences in the types of resources acquired by BPA compared to those acquired by the suppliers that serve the remainder of the regional demand.**

For example, BPA may select resources with higher capital costs and lower environmental costs than a supplier more oriented toward near-term marketing. As a result, BPA resource acquisitions would include more energy conservation and less thermal generation than the other supplier’s. If one alternative were to result in less resource development by BPA and more development by that other supplier, that alternative could lead to more land use or air quality impacts of thermal resources.

4.1.2.2 Resource Operation

Some BPA customers own generating resources. BPA's business decisions affect decisions by those resource owners about how to operate their resources and which power services to produce for themselves or to offer for sale. As with resource development, decisions by BPA customers about how much power service to buy from BPA compared to other suppliers will affect resource owners' decisions on which services to provide from their own generating resources. For example, a thermal generating plant may be used to provide baseload energy or peaking power, depending on the price and availability of peaking services from BPA. A decision by the owner of the plant to emphasize peaking power, rather than to purchase peaking services from BPA, could result in different air and water impacts of operating the plant than a decision to operate the plant for baseload energy. (Note: Federal hydro operations are limited by constraints established by Federal operating agencies in consultation with the NMFS under the ESA. Impacts of Federal hydro operations are described in section 4.3.4 and also are addressed in the SOR DEIS.)

4.1.2.3 Transmission Development and Operations

For many years, BPA has been the dominant developer of high-voltage transmission capability for the PNW, and for interregional transactions between the PNW and other regions. BPA facilities provide three-fourths of the high-voltage transmission capacity in the PNW. Generating utilities provide virtually all of the remainder. Depending on the costs and conditions of BPA transmission service in relation to the costs of new transmission construction, utilities developing resources or purchasing power from other suppliers may choose to develop their own transmission facilities rather than purchase equivalent services from facilities to be constructed by BPA. Differences in land use impacts could result from differences in voltage; for example, BPA might construct a 500-kV line where another developer would construct a 230-kV line. Increased land use impacts could also occur from construction of redundant capacity, where both BPA and non-BPA transmission were available to serve the same loads or resources.

Where BPA and non-BPA transmission facilities could provide the same service, a customer might choose between them based on price, availability, and other conditions of service. Changing transmission suppliers could alter line loadings and revenues among BPA and non-BPA suppliers. Different line loadings can change potential electric and magnetic field (EMF) exposure. The most significant portion of the transmission system with diverse ownership is the PNW/PSW Intertie. On the other hand, relatively few transactions over the within-region network currently offer customers a choice of suppliers because of the limited amount of non-BPA transmission and the central function of BPA transmission facilities. Where the non-BPA supplier of transmission service shares ownership with BPA, operations to supply a customer from another owner's share rather than BPA's would be the same; the only difference would be who receives the revenue.

4.1.2.5 Consumer Behavior

BPA's business decisions affecting its wholesale customers will ultimately influence end-use consumers through the cost of electric power or other conditions of electric utility service. Environmental impacts may arise from the actions consumers take in response to those costs or conditions. This market response is dominated by price effects. The retail price of electric energy, which results from utility decisions on resource development, resource operation, transmission, and retail rate design, may motivate a consumer to make changes in electric energy consumption. The principal choices available to consumers are as follows:

- to improve the efficiency of energy use (for example, by weatherizing residences or using energy-efficient appliances or lighting);
- to switch fuels (such as switching from electricity to natural gas or wood for space heating);
- to change the timing of use (as in response to time-of-day pricing, e.g., running laundry appliances and dishwashers at night); or
- to curtail use (foregoing energy use by reducing lighting, heating, or cooling).

These behaviors have environmental impacts, such as air emissions from combustion of natural gas or wood for heating, or potential health hazards of foregone consumption of electricity. These responses also result in changes in the amount and timing of electrical loads that affect the need for power system services.

Consumer behavior may also be affected by terms of utility service that permit interruption of power deliveries under predefined conditions. Utilities may offer discounted service to industries or other consumers in exchange for interruption rights to provide system reserves. The environmental impacts of such arrangements could be both beneficial and adverse: interruption could reduce impacts of consumptive uses, but socioeconomic effects of production and employment losses could offset the benefits.

4.1.3 Environmental Impacts

BPA can estimate the generic environmental impacts resulting from market responses, such as the impacts of different energy resource types, transmission construction, or consumer actions. These impacts are addressed in section 4.3. The generic environmental impacts of market responses can then be applied to the cumulative market responses of each of the alternatives (in section 4.4) to assess the environmental impacts of the alternatives. To establish the relative impacts among the alternatives, the cumulative environmental and socioeconomic impacts of each alternative are compared to those of the Status Quo alternative. The impacts are also presented as they would vary under a river system operation strategy that would sharply reduce power production capacity.

Environmental impacts addressed in the EIS include:

Physical Environment:

Air quality

Water quality

Land use (e.g., from power resource and transmission construction, irrigated agriculture)

Human health and safety (e.g., from electrical hazards, EMF exposure).

Socioeconomic Environment:

Effects of changes in products, services, and rates on:

Residential, commercial, industrial, and agricultural sector end users of electricity

DSIs

Economic effects on landowners in transmission rights-of-way.

Note that the analysis in this EIS is directed at policy-level decisions, rather than decisions on specific sites for development. It is not practicable to address site-specific impacts, due to the large number of potential sites for facilities and the uncertainty about the development of any individual site. See Section 1.4, Decisions To Be Supported by This EIS.

4.2 Market Responses by Issue and Alternative

This section describes the market responses to each of more than 20 policy issues defined in chapter 2, first in general terms and then specifically for each of the six alternatives. Table 4.2-1, at the end of this section, summarizes the market responses to each of the issues. The figure that begins this chapter shows how the market response analysis leads to estimates of environmental impact.

4.2.1 Products and Services

4.2.1.1 Bundling or Unbundling of BPA Power Products and Services

Background

Most BPA power products and services are now marketed in “bundled” form; that is, BPA provides a variety of different power system services as a package under a single rate schedule. The market response to bundled service depends on whether continued BPA bundled service will be competitive with services offered by other suppliers. Although BPA bundled service at current prices will continue to be attractive to many of BPA's customers, increases in BPA's revenue requirements would lead to increases in the price of bundled service. Bundled services at higher prices would have to compete with separate services offered by other suppliers; customers are now exploring alternatives to BPA service, such as baseload energy resources and purchases of power from other suppliers over interties.

If services from other suppliers cost less than BPA bundled service, BPA's utility customers could adopt service arrangements under their current power sales contracts (computed requirements service) that would allow them to obtain some services from these other sources while continuing to meet the remainder of their loads with Federal power. They would likely continue to rely on BPA for services derived from the flexibility of hydro operations, but they could be expected to obtain basic energy and capacity services, such as those that are produced by CTs, from other suppliers. BPA's share of regional loads would decline and the share of energy resources provided by other suppliers would increase.

Unbundled and rebundled BPA power services would enable BPA's customers to manage their costs by purchasing only services they actually would use. Rather than price a bundle of products together, BPA could price products and services separately to provide price signals reflecting the costs of services or to compete with other suppliers. Customers purchasing power and services in the market could purchase unbundled BPA services such as load shaping or generation reserves. These customers would select BPA services that were competitively priced and that matched their own load requirements and resource portfolio. BPA could offer a rebundled package of full requirements services for customers who would rely on BPA for all of their power needs.

Separate pricing of BPA services could stimulate the development of markets for individual services. Sales of unbundled services would be made by the supplier, whether BPA or another seller, who could provide services that customers demand at lowest cost. Compared to continued bundled services, the desirability of BPA service would be based on the individual product and price, rather than on the price of the whole bundle of products. The market response would depend on relative prices, i.e., on whether BPA's products and services were below, above, or near competitors' prices. With the large base of Federal hydro generation, BPA has a significant advantage in both cost and flexibility to keep its power products competitive.

Market Response

Status Quo

BPA would continue to offer historical bundled services. Rising costs of BPA programs would lead to increased rates for bundled service, while the price of non-BPA resources would follow the market and continue to be stable or decline. Customers would increase purchases of non-BPA resources, especially for firm baseload energy. As customer loads shifted from BPA to non-BPA resources, BPA rates would continue to increase, as costs were spread over sales to smaller total loads.

BPA Influence

BPA would offer unbundled services. Unbundling would enable BPA to maintain sales of its most competitive and valuable products to produce revenue to pay for resource and fish and wildlife actions. Surcharges to customers who failed to comply with the Council's Power Plan and F&W Program would change the economics of those customers choosing between BPA and other suppliers for power system services. To ensure that customers do not shift load away from BPA, BPA could include a stranded investment charge that customers would pay if they left the system. Current contracts could continue giving BPA a captive customer base through 2001. For some customers, the burdens of surcharges or conditions on BPA service would outweigh the benefits of unbundled service, resulting in their greater reliance on non-BPA suppliers to meet their needs for power products and services. BPA could use its influence to pursue and implement a regional fish and wildlife conservation tax.

Market-Driven

BPA would offer unbundled services. As with the BPA Influence alternative, unbundling would enable BPA to maintain sales revenues. However, without the surcharges of that alternative, customers would have less incentive to shift load away from BPA if they did not comply with the Council's Power Plan and F&W Program.

Maximize Financial Returns

BPA would offer unbundled services to compete with other suppliers. BPA would package its unbundled products to leverage its competitive advantages and maximize revenues. BPA would let non-competitive loads go to other suppliers but would aggressively create and price products to compete for desirable loads, including loads it has not traditionally served. Due to cost cutting, the lack of compliance surcharges, and marginal-cost, firm-power price signals, more regional load would remain with BPA under this alternative than under the other alternatives.

Minimal BPA

For administrative simplicity, BPA services would be sold in the same bundles as at present. Because BPA would not acquire additional resources under this alternative, all resources would be developed by others.

Short-Term Marketing

BPA would offer unbundled services in short-term transactions. Unbundling would provide the advantages of flexibility in marketing noted above, which would add to the flexibility provided by short-term marketing. As a result, BPA loads would increase over the Status Quo alternative, and the amount of load shifting from BPA to non-BPA suppliers would be comparable to that under the Market-Driven alternative.

4.2.1.2 Surplus Products and Services

Background

Currently, BPA makes sales of surplus firm power, both within and outside the PNW, as system operations or long-term planning indicates that surplus firm energy or capacity is available. Resource planning traditionally has been oriented toward providing sufficient resources to meet forecasted loads, and not toward creating or sustaining firm surplus generation capability for marketing purposes. BPA has considerable experience in marketing surplus Federal power from its efforts to market the large firm surpluses that forecasters identified in the early 1980s. Past BPA surplus firm power sales have been both short- and long-term. BPA's current sales of surplus power include contract provision for recall and conversion to exchanges so as to accommodate regional preference directives while supporting long-term transactions with parties outside the region. From this experience, BPA has established ongoing business relationships with extraregional parties; these relationships facilitate marketing of available surplus power products.

Surplus power products may be attractive to some customers that currently receive requirements service. BPA could create flexible offers tailored to other needs with fewer statutory mandates than requirements service.

The tentative nature of BPA power surpluses has made surplus power marketing, particularly to parties outside the PNW, a function of opportunity rather than a predictable element of BPA's overall marketing. The marketability of such opportunity products may change as the west coast bulk electric power market becomes more competitive, with open transmission access, more independent power producers, and the near-term availability of generation from California. BPA “as-available” surplus sales must compete with suppliers who offer power products on a more consistent basis, or BPA must find ways to maximize revenues and relationships with those suppliers. An alternative surplus marketing strategy would be for BPA to plan its resources and operations so that certain surplus products were available predictably from year to year, or for long-term transactions. If this strategy accurately anticipated the surplus products needed by the market, and BPA made sales, then its revenues would be enhanced.

Without a deliberate BPA strategy to acquire resources to support marketing surpluses, resource development would not change from the present practice. If BPA planned to establish long-term business relations with extraregional parties, resource acquisitions would have to include sufficient resources to support such relationships. Resource development in support of surplus marketing would tend to emphasize resources that could support the flexibility of the Federal hydro system, such as displaceable thermal generation, probably combined-cycle CTs, or perhaps dispatchable thermal generation, i.e., single-cycle CTs.

Market Response

Status Quo

Due to BPA's committed resource acquisitions and the expected shift of several hundred aMW of load from BPA forecasted firm power requirements to non-BPA supplies, BPA would have a substantial surplus under this alternative, which would be marketed as available, consistent with established BPA surplus marketing practices. BPA resource development would not change, but intertie transmission might be used more to market surplus power. Utility resource operations would shift to allow displacement with BPA power when practicable.

BPA Influence

BPA loads would be less than under the Status Quo alternative, so BPA could have more surplus power, given the same resource development. As with the Status Quo alternative, this surplus power would be marketed under BPA's established surplus marketing practices. Resource development would not change, but, as under the Status Quo, the intertie might be used more to deliver surplus sales.

Market-Driven

BPA would expand choices of products for sale to extraregional parties, including non-PNW IPPs/brokers/marketers within the constraints of regional preference. BPA would have to acquire additional resources to fulfill contract obligations above its expected PNW firm load obligations. The type of resources needed would depend on the types of services in demand from extraregional parties. The most valuable resources to support extraregional sales would be those that could enhance the flexibility of the hydro system. They might include measures to reduce peak demands within the PNW and actions to increase nighttime minimum loads so that BPA could accept return energy more readily. BPA might develop or invest in some transmission to improve access to extraregional customers.

Maximize Financial Returns

BPA would seek to establish medium- to long-term extraregional contracts, based on the assumption that regional preference legislation would change so that BPA was not constrained by regional preference. BPA would develop resources necessary to support such contracts, probably by measures similar to those described for the BPA Influence alternative. Because BPA's loads would increase under this alternative, resources acquired to support surplus sales would be in addition to those needed to serve its PNW customers. BPA might develop transmission facilities to improve access to new marketing opportunities.

Minimal BPA

BPA would not acquire resources under this alternative. Any surplus sales would be on an occasional basis, arising from changes in annual capacities and firm load obligations under long-term sales contracts with customers.

Short-Term Marketing

BPA would offer the same products to the surplus market as to its regional firm power customers. Short-term marketing would favor short-term BPA resource acquisitions, presumably system power deliveries rather than resource output contracts. The amount of power resources BPA would acquire would depend on the appeal of short-term products in the market; short-term transactions should be more attractive when the cost of power services appears to be declining, and less so when power costs are stable or increasing.

4.2.1.3 Scope of BPA Sales

Background

The scope of BPA's current power sales and the forecasted firm power requirements loads for its customers are the basis for BPA resource acquisition planning. By expanding the scope of sales to include new customers, BPA could increase its sales of power and transmission services, and increase its revenues—assuming that it had resources and facilities available or could cover costs of developing new ones. Some of these potential expansions of BPA markets—for example, sales to utility pools or cooperatives, or to IPPs/brokers/marketers—would add marketing flexibility and enhance BPA's competitiveness. Some expansions, such as service to new Federal agencies either within or outside the region, or to retail consumers, such as large industries now served by utilities, would also expand BPA sales at the expense of other sellers. Regardless of the potential revenue benefits, service expansions that lead BPA to compete directly with other utilities would raise sensitive issues about the rights of sellers now serving those loads. If implemented, these expansions could alienate sellers and risk losses to BPA sales. Any such expansion of the scope of BPA sales would have to be supported by BPA's statutory authority, or by appropriate revisions to that authority.

To the extent that BPA expanded its sales of surplus power, any surpluses due to resource overbuilding would be reduced. Ultimately, BPA would have to acquire additional resources to supply expanded sales.

Status Quo

Sales would be limited to existing customers. No additional resources or facilities would be needed.

BPA Influence

A wider scope would allow sales to utility pools and IPPs/brokers/marketers. Sales to utility pools would replace or retain existing BPA customer loads, causing little change from current resource needs. Sales to IPPs/brokers/marketers might in part replace loss of sales to existing loads, but could also indirectly supply loads BPA is not currently serving, potentially leading to additional BPA resource acquisitions. Sales to IPPs/brokers/marketers might in some cases lead to development of additional transmission facilities, if necessary to deliver power to IPP/broker/marketers' purchasers. BPA resource acquisitions would increase; non-BPA acquisitions would correspondingly decrease.

Market-Driven

Same as BPA Influence alternative.

Maximize Financial Returns

BPA would sell to the broadest possible range of purchasers to maximize revenues. Effects would be the same as those of the BPA Influence and Market-Driven alternatives, but increased due to the broader range of BPA marketing. Sales to retail consumers, if permitted, and to new Federal agencies might replace loss of sales to utilities and would compete with retail utilities serving those loads and others similarly situated. BPA resource development and perhaps also transmission needs would increase.

Minimal BPA

Scope of BPA sales would be limited to existing customers and existing production capability. Limited supplies might eventually restrict BPA sales to customers receiving long-term allocations of Federal system capability.

Short-Term Marketing

Same as BPA Influence alternative.

4.2.1.4 Determination of BPA Firm Loads

Background

Another important influence on BPA resource planning is the determination of its firm loads. This determination is done primarily under the terms of power sales contracts, and sets BPA's anticipated firm power obligations. Several specific issues are part of the determination of BPA firm loads.

Customers' Net Requirements

For customers without generating resources, BPA now meets their entire actual firm load. For requirements customers that own their own generating resources, BPA's firm obligation is limited to the customer’s firm load requirements, less its dedicated resources. BPA's power obligation would vary according to how firm load is calculated, the amount of power the customer’s resources can be assured to produce, and whether some loads are excluded from firm load. The greater BPA's firm power obligation, the more resources or power purchases BPA would need to meet that obligation.

Definition of Full and Partial Requirements

Under unbundled marketing, BPA would offer either full or partial requirements firm power service. Full requirements service would be available to customers that do not operate or participate in resources sold in the wholesale power market, i.e., nonmarketing customers. Those that participate in the market would take partial, instead of full, requirements service. Different obligations would apply to partial requirements service; examples would include a notice period of 9 months prior to the time when rates go into effect before BPA would be obligated to serve additions to firm load, and a take-or-pay purchase obligation.

This short notice period could cause a rapid reduction of BPA firm loads if BPA costs were significantly higher than the market, but would give utilities the ability to choose the service that best meets their needs as their situation and the market change. Longer notice provisions would keep customers from having as much opportunity to participate in the market and its benefits. If a customer chose to reduce its Tier 1 load, it would have to give BPA 7 years' notice to bring its load back up.

The amount of load BPA serves as full versus partial requirements would affect the uncertainty of BPA's firm load obligations on an operating basis and BPA's resource development risk. Higher full requirements loads would mean that BPA would be obligated to meet larger amounts of real-time actual loads under full requirements contracts. On the other hand, higher partial requirements loads could mean a lower total firm load obligation and a larger market for unbundled power system products and services for both BPA and other suppliers. If BPA's unbundled products and services were priced competitively, there should not be a price incentive for partial requirements customers to obtain unbundled power system services from non-BPA suppliers. In other words, if BPA actions caused more customers to choose partial requirements, BPA would have to provide more flexibility services rather than the baseload services that have been the focus of the past.

Resale of Federal Power

One of the purposes of Federal hydropower development has been to provide low-cost power to publicly owned utilities and to provide the benefits of Federal power to the consumers served by those utilities. BPA's current power sales contracts support these purposes by prohibiting the resale of Federal power. As the market for electric power becomes more competitive, allowing resale might benefit publicly owned utilities and their retail customers. For example, resale of Federal power saved through energy conservation programs provides a mechanism (called a "conservation transfer") by which small public utilities can finance conservation activities. Under a conservation transfer, based on modification in BPA statutes, BPA would have to deliver power to the reselling utility that would be more than that customer's actual loads. Some forms of resale might be appropriate to provide flexibility to customers that would purchase power from BPA under take-or-pay conditions. Generally, if BPA permits resale of Federal power, determining both BPA's firm obligation to that customer and BPA's total firm obligation becomes simpler, and the certainty of BPA's obligations increases. The general effect of this certainty would be to increase BPA's incentives to adopt certain resource development strategies, such as options contracts for resource output or reliance on system purchases, rather than to acquire long-term resources to meet its firm load obligations.

Delivery of Power Under Residential Exchange Agreements

At present, BPA exchanges power with certain PNW utilities under the Residential Exchange Program (RPSA). The program provides the benefits of Federal low-cost power to residential and small farm consumers by exchanging power at BPA's Priority Firm (PF) rate for equal amounts of power at the participating utility's average system cost, which is typically higher than BPA's PF rate. The amounts of power are equal, and in fact no power is actually transferred between BPA and the exchange parties. The result is a financial transaction, with payment going from BPA to the participating utilities, which are required to pass the rate benefits through to their residential and small farm consumers. If BPA can provide power at lower cost than an exchanging utility's average system cost, though, the transaction could become an actual power delivery, with BPA delivering Federal power to the exchanging utility, and providing power from the lower-cost source. This is known as an "in-lieu" purchase under the exchange agreements. Although there have been no in-lieu transactions under the exchange program so far, there is potential for BPA to exercise its in-lieu rights by acquiring low-cost power in the market, and possibly by using BPA power surplus. BPA actions to reduce barriers, such as the 7-year notice in the current residential exchange contracts agreements for in-lieu, will also increase the likelihood of BPA providing in-lieu power in the future. If BPA began to make in-lieu purchases, the purchases in effect would shift resource acquisition from the exchanging utilities toward BPA. It could also result in more BPA power being used in the region, rather than being sold outside of the region. The exchanging utilities would have less need for new resources, because BPA's in-lieu power would serve their customers and they would have the power they otherwise would have exchanged with BPA. BPA's acquisitions would increase by the amount of the in-lieu purchases unless BPA were serving them with surplus power.

9(c) Deduction

The Northwest Power Act (Section 9(c)) provides that, if a PNW customer of BPA exports a resource from the region such that BPA's firm requirements obligations to that customer or any other customer would increase, then BPA must reduce the firm requirements load of that customer. Section 9(c) deductions would not be made if certain conditions were met (such as inability to conserve or retain the power for service to PNW loads by reasonable measures); then both BPA's firm power obligations to the customer and BPA's need to acquire resources could be reduced. Under some alternatives, for example, where a partial requirements customer purchases fixed amounts of BPA power, firm requirements may be defined such that exports do not increase BPA's obligations. In those cases, BPA would not need to reduce the customer's firm requirements.

DSI Contract Demand

Present DSI contracts (Section 8(a)(1)) define the entire DSI load as firm for operating purposes, but exclude the top quartile from firm loads for resource planning purposes. This distinction complicates BPA operational planning. If only the bottom three quartiles of DSI load were considered firm load, BPA planning would be simplified, and uncertainty in BPA firm resource requirements would be reduced. BPA could eliminate quartiles in new contracts or otherwise modify terms of service. The modules describe DSI service options; they are evaluated in section 4.5.

Allocation in Insufficiency

Following the direction of the Northwest Power Act, existing power sales contracts provide a formula for allocating available Federal firm power if BPA firm load obligations exceed available firm power. This allocation mechanism limits BPA's contractual and statutory obligation to meet customers' firm power requirements on 5 years' notice for capacity and 7 years' notice for energy. The allocation formula applies statutory priorities among BPA's customers, makes adjustments for customer resource development, and redistributes any allocations that exceed a customer's firm requirements. Since the contracts were signed, BPA has never had to allocate firm power under the contract formula. Possible variations in the allocation procedure include different notice periods, provisions to address treatment of DSI loads, and adjustments in customers' allocations based on energy conservation. Although insufficiency of resources should be less likely with a competitive bulk power market, BPA's allocation formula could influence customers' resource development decisions, such as DSI decisions on how much of their load to place on BPA, or utility decisions about energy conservation activities, which could in turn alter BPA's firm load obligations.

The combined effect of the issues affecting BPA firm load obligations is potentially to shift resource development between BPA and other suppliers. More inclusive determinations of BPA firm loads add to BPA's potential firm load obligation and therefore increase the potential need for new resources. Less inclusive determinations reduce BPA's potential obligation. Whether BPA actually has responsibility to serve these loads depends on customers' decisions on whether to obtain service from BPA.

Market Response

Status Quo

BPA and non-BPA resource development would be unchanged from present conditions. BPA resource surplus would be reduced with delivery of Federal power under residential exchange agreements, and the corresponding acquisition of power in lieu of exchange. Resource development by exchanging utilities would decrease.

BPA Influence

Same as Status Quo, except that allowing resale of Federal power would increase BPA load certainty.

Market-Driven

BPA firm loads would be reduced if customers choose other suppliers, but flexibility in contract terms would lessen the incentives for customers to reduce their BPA loads.

Maximize Financial Returns

Uncertainty in BPA loads would be reduced through specific negotiation of BPA obligations in individual transactions with customers.

Minimal BPA

BPA would not acquire resources; therefore, BPA loads would be determined by Federal system capability, regardless of resale.

Short-Term Marketing

Same as Market-Driven.

4.2.1.5 Marketing to Support Power System Stability and Quality

Background

Currently, BPA includes its costs to maintain system stability and power quality, such as costs for voltage support and harmonic control, in its prices for all customers. If BPA shifted costs from its customers collectively to individual customers that impose stability costs on the system, customers might be influenced to reduce their stability costs to BPA, either by persuading consumers to avoid operations that burden the Federal system, or by installing equipment to compensate for loads that adversely affect system stability.

Conversely, soliciting reserves from customer loads could create a market for reduced quality service that would reduce costs to consumers (most likely large industrial loads) that were willing to tolerate interruptions, in effect shifting the costs of higher quality service away from tolerant loads and toward intolerant loads. Such reserves might also provide a mechanism for financially stressed customers or consumers to reduce costs.

If customers could choose a lower quality of service, either in terms of energy supply or service interruptions, it would create opportunities for more efficient use of the power system. Nonfirm energy might be used to some extent to supply lower-priority loads, and nonfirm transmission could be used to deliver the power. Transmission facilities would likely operate at higher load factors. These results would reduce the need for additional generation and transmission facilities, avoiding the costs and rate impacts of new facilities.

For consumers receiving service at lower quality, the effect would depend on the arrangements for lower quality service. Retail service interruptions (most likely to large industrial loads) to accommodate interruptions in BPA service could be prearranged, with advance notice, amount of load, duration, and frequency of interruption established by contract. Such conditions, especially if accompanied by reductions in power costs, might result in investments by affected consumers in protective devices, load controls, or actions to adapt to interruptible service. If a utility customer accepted lower quality service without such preparations, the result could be more disruptive due to unexpected power outages, potentially leading to reductions in consumer loads due to fuel switching or shutdowns if consumers chose not to tolerate service interruptions.

Market Response

Status Quo

Most system stability costs would be shared by all customers in power rates. Some standards would be enforced through power billing adjustments. DSIs would continue to provide stability reserves in exchange for a rate discount. BPA would meet stability and power quality needs largely by installation of control devices.

The DSI market for nonfirm energy and DSI system stability reserves would continue to allow BPA to avoid acquiring the firm resources and reserve capability necessary to serve an equivalent amount of firm load.

BPA Influence

Use of load reserves would be broadened to include retail industrial loads and other potential suppliers including IPPs. BPA would charge stability costs directly to responsible customers under its customer service policy. BPA's need for system control devices and the accompanying costs would be reduced.

Load interruption reserves (to the extent provided from customer loads) and lower-priority service options could reduce or delay the need for additional firm power facilities, both generation and transmission. It could also increase the load factor, and thus efficiency of use of existing facilities. Load interruptions causing occasional shutdowns could reduce production at affected facilities, with consequent economic effects.

Market-Driven

Same as BPA Influence.

Maximize Financial Returns

As in BPA Influence, use of load reserves would be broadened. Pricing according to quality of service would provide customers with price signals and incentives to consider alternatives for quality of service. BPA and its customers could negotiate different levels of service quality in individual transactions.

Minimal BPA

BPA would not offer quality of service options; DSI reserves would be limited by firm power available to DSIs under long-term contractual sales of Federal power. System stability costs would be charged as under Status Quo.

Short-Term Marketing

Same as BPA Influence, except that BPA might obtain reserves from consumer load on a short-term basis as necessary to support short-term marketing.

4.2.1.6 Unbundling of Transmission and Wheeling Services

Background

BPA provides both transmission and wheeling services over the main grid, fringe, and delivery portions of the FCRTS as well as interties. Currently, BPA's transmission service delivers Federal power to full and partial requirements customers; it amounts to approximately two-thirds of the activity on BPA transmission facilities. Presently, costs to transmit Federal power are included in the rates charged for the power.

BPA also provides transmission of non-Federal power on Federal transmission facilities (wheeling). For most of its wheeling service, BPA charges at a "postage stamp" rate, which includes a capacity and energy component but, in most cases, does not include a distance component (short-distance discount). Smaller amounts of transmission services reflect the cost of specific facilities or the distance the power is wheeled.

All BPA transmission services are based on "one-utility" planning; that is, BPA evaluates the need for transmission facilities with a long-term regional focus, as if the entire transmission and generation system were designed and operated efficiently by a single utility. BPA's transmission system is planned and constructed to a single set of reliability criteria, although actual reliability varies by area, depending on the amount and kind of load served. In addition, BPA provides network wheeling (e.g., transmission from multiple points of integration to multiple points of delivery) on both a firm (assured) and nonfirm (as capacity is available) basis.

BPA could unbundle its transmission and wheeling services in a number of ways:

- BPA's power rate schedules could charge separately to transmit Federal power, with variables for location or other attributes.
- BPA could charge for specific transmission support services (ancillary services) such as harmonics control and reactive support, or sets of facilities such as fringe, delivery, and generation integration segments (services that are now generally provided as part of transmission and/or wheeling services).
- BPA could charge separately for the use of specific new or existing main grid or intertie facilities.
- BPA could offer transmission services subject to curtailment under specified circumstances, e.g., transmission over a specific path with the right for BPA to cut service under specified conditions.

Choices related to unbundling transmission and wheeling products are closely related to choices about pricing (see section 4.2.2.2, Transmission and Wheeling Pricing). In general, the unbundling choices can be viewed along a spectrum of economic efficiency versus uniformity of pricing. BPA's current bundles of transmission services reflect a mix of uniform pricing and efficiency goals: basic sets of services generally offered at a single set of systemwide prices. If BPA were to unbundle transmission services, it might offer more choices that could support more efficient use of transmission system resources. However, costs for some utilities purchasing transmission or wheeling services would increase, while for others they would decrease.

EPA-92 and national transmission policies could affect the transmission services BPA offers in all the Business Plan alternatives described below. Under EPA-92, utilities and non-utility generators can request FERC to order a utility to provide service on the utility's transmission system, including ancillary services, and to construct new transmission capacity as necessary to provide the service. BPA already provides wheeling service over unused capacity on its transmission system, but EPA-92 might cause BPA to add transmission capacity to support FERC-ordered transmission service.

Market Response

Status Quo

BPA would continue to offer its current mix of transmission and wheeling products under existing rates schedules and contract terms, to the extent that doing so is consistent with FERC orders under EPA-92. EPA-92 specifies that costs attributable to providing wholesale transmission service pursuant to a FERC order for such access should be recovered, to the extent practicable, from the applicant, and not from the transmitting utility's existing wholesale, retail, and transmission customers. This provision of EPA-92 might result in some increased degree of unbundling of BPA's transmission services in order to charge appropriately for these transmission facilities and services. Implementation of EPA-92 might also lead to some marginal increase in transmission development in response to FERC orders to provide transmission service.

BPA Influence

BPA would offer unbundled transmission and wheeling services, with priority access provided to the integration of resources that comply with the Council's Power Plan and F&W Program. Although EPA-92 states that one standard for FERC review of wheeling requests is “public interest,” it is not clear that this alternative would be fully consistent with FERC's implementation of EPA-92's transmission access provisions. For purposes of this alternative, BPA assumes it would be consistent. To the extent that BPA's customer utilities comply with the Power Plan and F&W Program by planning and acquiring resources on a long-term least-cost basis, this alternative would support long-term one-utility generation resource planning. Customers that do not comply with the Power Plan and F&W Program (e.g., by not implementing least-cost plans) would be given lower priority access to BPA's transmission system; in response, they could decide to comply with the Power Plan and F&W Program, could attempt to find transmission services from alternate sources, or could try to free themselves from the constraints of this policy by local generation and/or construction of their own transmission facilities if feasible. In the latter cases, transmission and generation development would happen less efficiently than under the Status Quo alternative.

Market-Driven

BPA would provide its customers with a broader range of choices of wheeling services. Services could include:

- separate point-to-point and network wheeling services;
- transmission services on specific contract transmission paths with options of two or three levels of curtailment; and
- separate subtransmission and ancillary transmission services (reactive support, control area services, etc.).

Providing more choices for wheeling services might generally promote more efficient development and use of facilities for transmission of non-Federal power. This effect would increase if the unbundled services were priced on an incremental basis. Utilities and non-utility generators would receive clearer price signals about the specific costs of wheeling services. To the extent that greater unbundling supports more efficient transmission system development, new generation would also be developed more efficiently, as utilities and non-utility generators have better information and price signals about the costs of delivering power.

Unbundling of wheeling services would increase efficiency over the Status Quo alternative. It might, however, increase transmission costs experienced by parties that purchase wheeling services from BPA, and might consequently lead to greater variation in the regional distribution of costs and services. However, power and wheeling customers would continue to be charged their proportionate share of the costs of the FCRTS. The delivery of Federal power would continue to be included in charges for power purchasers (rather than being offered as a separate product). This bundling of power and transmission components of power costs would continue to provide a basic, broadly available service at systemwide embedded costs.

Maximize Financial Returns

BPA would maximize revenue from specific investments. Full and partial requirements customers would pay separately for the delivery of Federal power (i.e., transmission costs would not be rolled into power rates). Each product would be designed and priced to maximize BPA net revenues. Because EPA-92 specifies that all costs for transmission service must be recovered from applicant and charges for transmission service pursuant to FERC orders must be based on cost-recovery, BPA may be limited in charging prices for transmission and wheeling services that were significantly different from the underlying costs of providing the service. In addition, BPA's organic statutes require BPA to recover the costs of its transmission system from Federal and non-Federal customers based on their use of the transmission system. Within the current statutory framework, however, this alternative could support somewhat greater efficiency in transmission and generation development by offering clearer price signals for specific wheeling and transmission services.

The efficiency benefit might come at the cost of less uniform pricing: while for some customers, overall costs might drop, other customers might find that specific transmission or wheeling services that were previously rolled into the broader BPA power or wheeling products now had significant new costs. For these utilities, increased costs might lead to substantial rate increases and/or decreases in the level of service purchased from BPA. Some utilities are located where it is more expensive to provide transmission services (e.g., far from the existing Main Grid transmission system, or in the Puget Sound area, where existing transmission is constrained). These utilities might tend to develop more local generation and/or invest in more conservation in order to reduce overall costs of service. Utilities located where transmission can be provided at lower cost (e.g., utilities near the Main Grid transmission system on the east side of the Cascades) might rely more on power purchases or out-of-region generating resources.

Minimal BPA

BPA would offer transmission and wheeling services on its existing facilities under long-term contracts, but would not voluntarily construct new transmission facilities (although, pursuant to EPA-92, FERC might order BPA to do so). For administrative simplicity, transmission and wheeling services would be sold in their existing bundles. In the long term, this alternative would lead utilities to develop their own transmission and generation facilities independent of BPA. To the extent that such facilities are planned outside the long-term, one-utility planning framework used by BPA, transmission (and therefore generation) development would be less efficient than under other alternatives. Under current Federal law, no regulatory mechanism would ensure efficient transmission development, particularly at the local level, although some states do regulate certain major transmission facilities on a case-by-case basis. Redundant facilities and/or greater amounts of transmission at lower voltages might be developed, as utilities independently assess the need for new facilities. Alternatively, transmission facilities that are cost-effective when viewed in a long-term, one-utility context might not be constructed.

Short-Term Marketing

BPA would market its current bundle of transmission and wheeling services, but would do so only under short-term (less than 5-year) contracts, to the extent consistent with FERC orders under EPA-92. Because utilities would have little planning certainty about their transmission services, the inefficient development of transmission and generation facilities described for the Minimal BPA alternative might also occur in this alternative.

4.2.1.7 Other BPA Services

Background

BPA has developed capabilities in connection with its power marketing and transmission activities that could be offered as revenue-producing services. These capabilities include financial services to aid customer resource development, environmental analysis and cleanup, communication services using facilities associated with the transmission system, and other technical, administrative, or information services.

In the near term, such services are not likely to produce significant revenues in relation to current and expected revenues from power and transmission products and services. If new BPA services are competitive, however, they could eventually generate substantial revenues, which could reduce the amount of revenue BPA would require from power and transmission marketing. As a result, BPA power and transmission rates might be lower and less uncertain.

Market Response

Status Quo and Minimal BPA

No new services. All required BPA revenue would have to come from power and transmission marketing.

BPA Influence, Market-Driven BPA, Maximize Financial Returns, and Short-Term Marketing

New services could potentially help to lower or stabilize BPA's rates, reducing the incentive for BPA customers to shift load to non-BPA suppliers.

4.2.2 Rates

4.2.2.1 Power Pricing and Rate Attributes

Background

Much of the market response to BPA's decisions is a function of pricing, as shown in figure 4.1-1. Pricing is the marketing manifestation of BPA's decisions on resource acquisitions, transmission development, fish and wildlife activities, and other costs. Although each element of BPA's costs contributes to BPA's revenue requirement and rate levels, the total revenue requirement ultimately drives the need to change rates. The exception is the Maximize Financial Returns alternative, where rates would not be based on costs, but on market prices for products and services BPA would offer. The pricing structure for power services would determine how costs would be distributed among customers and which costs customers would consider when comparing BPA services to those of other suppliers.

Many pricing and rate structure alternatives exist for BPA power products. The range of possible rate attributes and their market responses are addressed in detail in Appendix B. A simplified analysis of rates under the six alternatives is presented in section 4.4, together with conclusions about the effects of those rates on resource development and forecasted electrical loads. Depending on retail rate structure, consumers would pay prices reflecting the cost of new resources, and would apply energy efficiency measures, switch fuels, or reduce consumption. Effects of specific rate design modules are discussed in section 4.5.2.

Current BPA power pricing is based on anticipated average costs over the rate period, using BPA costs allocated to the production and delivery of power to customers. Rate schedules include time-of-day pricing for capacity; seasonal pricing for energy; market-indexed pricing for aluminum DSIs; discounts for quality of service to the DSI first quartile; and rates for customers with low load density or irrigation loads.

Alternative BPA power pricing could include:

- tiered rates for power or power services, with an initial block of service at one price, and additional purchases at a different, presumably higher price related to the marginal cost of new power resources;
- streamflow-based rates, to provide an incentive for consumers to shift power consumption to better match stream flows on the hydro system;
- seasonal rates, to provide an incentive for consumers to shift power consumption to better match overall power availability and cost;
- elimination of existing discounts, to provide more uniform price information to customers and consumers;
- surcharges for customers not in compliance with the Council's Power Plan and F&W Program or other purpose; or
- market-based pricing, with BPA prices set using information about costs and prices of alternative suppliers.

Market Response

Status Quo

BPA would continue to price power services under present ratemaking methodologies, including cost allocation and rate schedules. Rates would continue to rise as BPA's anticipated costs increase, improving the cost comparison of non-BPA supplies to BPA service. More customer load growth and some existing loads—especially among generating customers and DSIs—would switch to non-BPA suppliers, increasing the upward pressure on BPA's rates as increasing costs of continuing resource acquisition, transmission development, and other actions were distributed over a stable or possibly shrinking sales volume. If customers selected non-BPA suppliers, generation development would shift toward the resource choices of non-BPA suppliers and might increase the need for transmission facilities.

BPA Influence

BPA would sell rebundled firm power and services under a tiered rate, with the first tier limited to 75 percent of historical firm loads, and the second tier priced at the cost of new resources[1].

BPA would sell other power services as unbundled products at market-based rates. Irrigation discounts would be eliminated. Rates would include surcharges to customers not in compliance with the Council's Power Plan and F&W Program, and adjustments that priced power products according to streamflow on the hydro system. The tiered rate would provide an incentive for customers to obtain their firm power needs above BPA's first tier from alternative suppliers, but unbundled generation services, such as shaping or reserves, would add to the cost of non-BPA power, whether BPA or another supplier provided those services. As with the Status Quo alternative, if customers selected non-BPA supplies, generation development would shift toward the resource choices of non-BPA suppliers and might increase need for transmission facilities.

Full requirements customers would continue to purchase their full requirements from BPA, but the second-tier price would provide an incentive for those customers to implement their own conservation programs. The retail price resulting from BPA's second-tier price would also stimulate price-induced energy conservation, fuel switching, and reduced electric energy use by consumers.

[1] First-tier allocations could distinguish between customers that had engaged in energy conservation activities and those that had not, providing a larger first-tier allocation to those with more efficient loads through conservation actions. For the purpose of showing the effect of efficiency allocations, a 75-percent first-tier allocation serves as an average of larger and smaller allocations based on efficiency.

Market-Driven

In the short term, BPA might continue to sell power without using a tiered rate structure. In the longer term, as the marginal cost of power increases, BPA might sell rebundled firm power and services under a tiered rate. The first-tier price would apply to 90 percent of historical firm loads; the second tier would be priced at the marginal cost of power. BPA would market unbundled services at market-based prices. Irrigation discounts would be eliminated. As with the BPA Influence alternative, the tiered rate would provide an incentive for customers to obtain their firm power needs above BPA's first tier from alternative suppliers, but unbundled generation services necessary to support non-BPA power rates would add to their costs.

Also, as under the BPA Influence alternative, full requirements customers would continue to purchase their full requirements from BPA. However, the second-tier price would provide an incentive for utility-sponsored conservation programs and generating resources, while the retail price resulting from BPA's second-tier price (whether or not the retail price, too, were tiered) would stimulate price-induced energy conservation, fuel switching, and reduced electric energy use by consumers. The effect of the tiered rate in motivating customers to purchase from non-BPA suppliers would be less than under the BPA Influence alternative due to the larger first-tier allocation and the lower second-tier price. Compared to the Status Quo or BPA Influence alternatives, resource development would conform more to BPA's resource priorities (see Generation Acquisition, section in 4.2.3.2) than to those of non-BPA suppliers.

Maximize Financial Returns

BPA would price its products and services to the fullest extent possible based on market prices, with the goal of encouraging sales at a net financial gain. Because prices would not be tiered, any price signal would be limited to that of BPA's market-based price, and, consistent with BPA's marketing goal of maintaining sales, would not result in customers purchasing from non-BPA suppliers to the same extent that the BPA Influence and Market-Driven alternatives would. Because BPA would serve a greater portion of load growth, resource development would conform more to BPA's resource priorities than to those of other suppliers.

Full requirements customers would have a lesser price incentive to implement energy conservation programs than under the BPA Influence or Market-Driven alternatives, and the retail price effect of BPA's rates would be less than under the BPA Influence and Market-Driven alternatives.

Minimal BPA

BPA would sell bundled services at average cost under long-term contracts. For administrative simplicity, discounts and other rate attributes would be eliminated. Customers would have to obtain all of their requirements for power services beyond those available from existing BPA facilities, and committed under long-term contracts, from non-BPA suppliers. Generating customers could expand their resource acquisition and management activities to provide all of their new resource needs. Non-generating customers would have to develop resource acquisition and management capability, either individually or collectively via generating cooperatives or pools.

All customers would face the price of new resources for their incremental needs above BPA supplies, and would have corresponding motivations for energy efficiency.

Short-Term Marketing

BPA would sell rebundled firm power under tiered rates, and unbundled power services at flexible market-based rates in short-term transactions. Prices would be negotiated to reflect the allocation of cost risks between BPA and purchasers. Where BPA would bear the risks of price or supply uncertainty, the price would be higher, and the customer would have stronger incentives to purchase from non-BPA suppliers. Where the customer accepted risks, BPA's price would be lower. The extent to which customers purchased power and services from BPA compared to other suppliers would depend in part on the extent to which other suppliers' prices reflected these risks; if suppliers did not price according to risk, their prices might be more attractive than BPA's. Regardless of whether a customer relied on BPA or other suppliers, the wholesale price and resulting retail prices would tend to reflect the market price of new resources for all power services not provided by rebundled BPA firm power.

4.2.2.2 Transmission and Wheeling Pricing

Background

BPA's current transmission and firm wheeling rates are based on embedded costs incurred for transmission and incremental costs. The costs of transmitting Federal power are determined from the appropriate share of overall transmission system costs and are included in power rates. The cost of transmitting non-Federal power over BPA facilities is reflected in BPA's wheeling rates. The Integration of Resources (IR) rate for firm network wheeling is a "postage stamp" rate based on the embedded costs of the main grid and secondary transmission systems. The IR rate also includes a discount for short distances. Wheeling services under the Formula Power Transmission (FPT) rate are priced based on embedded costs using a formula that has a distance component. Certain transmission services are sold through rates that reflect the costs of using specific facilities (e.g., the Use of Facilities Transmission rate or the Townsend-Garrison Transmission rate over BPA's section of the Montana [Eastern] Intertie).

BPA could change how it prices transmission and wheeling services in a number of ways:

- BPA could charge the costs of transmitting Federal power to customers separately from power rates, instead of rolling those transmission costs into power rates as at present.
- BPA could offer discounts or impose surcharges for integrating specific resource types (such as renewables) or locations (e.g. west-side) for certain types of transactions (such as conservation transfers), or for other reasons.
- BPA could use opportunity cost pricing in its rates, subject to statutory constraints.
- BPA could increasingly use incremental pricing for transmission or wheeling over specific facilities, as appropriate.
- BPA could price transmission services in tiers, on the basis of new facilities and capacity versus existing facilities and capacity.
- BPA's wheeling rates could have zonal components (i.e., a hybrid of distance and "postage-stamp" rates).

Choices related to pricing transmission and wheeling services are closely related to choices about unbundling transmission and wheeling services (see Unbundling of Transmission and Wheeling Services, above). Choices about transmission and wheeling pricing can similarly be considered in terms of choices along a spectrum of economic efficiency versus uniformity of pricing. To the extent that BPA charges for specific, more narrowly defined transmission and wheeling services, or on the basis of incremental or opportunity costs, the transmission and generation system could be operated and developed more efficiently, because there could be clearer price signals that indicate the costs of delivering power.

Unbundling services and/or charging incremental or opportunity costs for specific services could, however, increase the range of costs that different utilities would experience for the services they receive from BPA. For example, if BPA charged separately for transmission of Federal power, and priced transmission services over new facilities at their incremental cost, the price for power delivered to the Puget Sound area could rise, as new cross-Cascades transmission facilities have to be added. The general result could be increased disparities in the prices utilities throughout the region pay for many services that are now priced more uniformly across the region on the basis of embedded costs (although, overall, BPA would have to continue to allocate costs of transmission between Federal and non-Federal customers on the basis of their use of the system). These disparities could influence customers' decisions on resource siting, or the marketability of resources output based on the influence of wheeling costs on the total cost to the purchaser of power services offered by different suppliers.

Market Response

Status Quo

BPA would continue to offer transmission and wheeling services under current rates schedules, to the extent that doing so was consistent with FERC's implementation of EPA-92's transmission access provisions and transmission pricing policy. Most wheeling might be provided under embedded cost pricing.

BPA Influence

BPA would offer a rate discount for wheeling energy from resources identified in the Northwest Power Act as priority resources (i.e., conservation, renewable resources, cogeneration, and high-efficiency resources) and/or for services for utilities that comply with the Council’s Power Plan and F&W Program, consistent with EPA-92. As stated under Unbundling of Transmission and Wheeling Services, providing this type of access priority for certain resources could support the goal of coordinated, long-term generation resource planning. Utilities that do not comply with the Council’s Plan and Program might see rate increases to cover the discounts. This could cause them to purchase transmission services from other sources or to build their own transmission or local generation, leading to less efficient transmission and generation development than under the Status Quo alternative. However, little effect on transmission and generation development decisions would be expected, since the transmission cost increase would be small compared to the overall project cost.

Market-Driven

BPA might continue to roll the costs of delivering Federal power into power rates; however, BPA power bills would identify the costs associated with transmission (which would have the same cost basis as applied to wheeling services). While continuing to use embedded costs for some wheeling services, BPA would also use more opportunity and incremental cost pricing and distance-based rates (consistent with national transmission pricing policy). The objective would be to offer more flexibility to some customers, and to provide clearer price signals about the costs to BPA of providing wheeling services.

New applications of distance-based rates and opportunity and incremental cost pricing might include:

- Zonal rates that charge for wheeling on the basis of the number of zones involved in the transaction.
- Use of opportunity costs to price intertie wheeling in congested conditions, when providing firm transmission service/access over Federal facilities would cause BPA to forego nonfirm transactions (e.g., when congestion over a specific transmission path caused BPA to spill water or use other, more expensive resources to meet its loads). Opportunity cost pricing would compensate BPA for such verifiable costs.
- Use of incremental costs that reflect the costs of constructing new facilities.
- Network service (as proposed in the 1995 FERC NOPR) that would provide additional flexibility and multiple points of integration and delivery and that would treat network service customers for planning purposes as if they were BPA load.

Pricing more wheeling services using cost bases other than embedded costs could promote more efficient development and use of transmission and generation facilities by other utilities and non-utility generators, and overall, could lead to a more efficient power system.

Maximize Financial Returns

BPA would rely much more on incremental, opportunity, and distance-based costs in its wheeling rates, and would charge separately for transmitting Federal power to customers. BPA's rate-setting objective would be to maximize financial returns on all facilities, particularly in the short term, with less concern for the widespread provision of basic transmission services. Both wheeling and transmission rates would more closely reflect market signals, and, in that respect, would promote efficient use of facilities; however, the range of costs faced by regional utilities would vary widely. Some utilities might face substantially increased costs, while others might experience significantly lower costs. In the context of EPA-92, and BPA's organic statutes, there likely would be limits to the market prices of transmission and wheeling services.

Minimal BPA

BPA would offer transmission and wheeling services on its existing facilities under long-term contracts, but would not voluntarily construct new transmission facilities (although, pursuant to EPA-92, FERC might order BPA to do so). For administrative simplicity, existing transmission and wheeling rate schedules would be used. In the long term, this alternative could lead utilities to develop their own transmission and generation facilities independent of BPA. To the extent that such facilities are planned outside the one-utility framework used by BPA, transmission (and therefore generation) development would be less efficient than under other alternatives. Although some states regulate major transmission facilities on a case-by-case basis, under current law no regulatory mechanism ensures efficient transmission development, particularly at the local level. Redundant facilities and/or greater amounts of transmission at lower voltages might be developed as utilities independently assess the need for new facilities. Alternatively, transmission facilities that are cost-effective when viewed in a long-term, one-utility context might not be constructed.

Short-Term Marketing

BPA would market transmission and wheeling services under its current rate schedules, but would do so only under short-term (less than 5-year) contracts to the extent not ordered otherwise by FERC under EPA-92. Because utilities would have little planning certainty about their transmission services, the inefficient development of transmission and generation facilities described for the Minimal BPA alternative would also occur in this alternative.

4.2.3 Energy Resources

4.2.3.1 BPA Conservation Acquisition

Background

Energy conservation includes a wide range of methods to save energy and capacity in the commercial, industrial, residential, and agricultural/irrigation sectors. Since 1980, when the Northwest Power Act was passed, BPA has acted as a catalyst to encourage energy conservation in its service territory. BPA has stimulated conservation by spending roughly $1 billion over the past decade building an infrastructure to support conservation activities and to prove their viability as an energy resource. BPA's energy conservation efforts have included a variety of approaches in all four sectors. BPA provided financial and technical support for State and local codes and standards and funded centrally designed programs, R&D programs, and some third-party program designs. In the past, most of BPA's energy conservation efforts used BPA-designed programs with a discrete set of measures that were to be taken as an all-or-nothing package. For the last few years, BPA has been testing third-party program designs such as billing credits, competitive bidding, and targeted acquisitions. Currently, BPA is trying to communicate the minimum standards, requirements, and conditions under which it will purchase conservation resources, allowing others to offer specific programs for conservation. In all approaches BPA has funded the programs, except for some limited cost-sharing.

If BPA funds fewer grant-type activities and instead promotes conservation through price-induced (power rate) incentives such as tiered rates and energy service charges, will the region continue to move toward maximizing its energy conservation potential? There is a disputable balance between the costs of conservation (such as lost revenues to BPA and other utilities and the amount of wholesale and retail power rate increases) and the benefits (such as the displacement of the need for new generating resources [avoided resource costs] and the decrease in participating retail consumers' bills). The point of this balance determines the level of conservation or energy efficiency that occurs in the region. Driving this issue are uncertainties about whether BPA's continued financial presence in energy conservation is needed, whether present or future regulatory processes through the states and/or public utilities commissions can stimulate utilities to continue improving energy efficiency, whether electric utilities will maximize energy conservation as part of their own least-cost planning, and whether consumers will increase conservation in response to rate increases.

Market Response

Status Quo

BPA would continue to fund and pursue the 660 aMW of energy conservation by 2003 set forth in BPA's 1992 Resource Program. It would continue to stimulate the region's energy conservation activities by spending approximately $1.3 billion from 1996 to 2003, through centrally designed programs and acquisition of other utility-designed projects in the region. BPA would continue to fund R&D for testing additional energy conservation opportunities. Because of the costs to fund energy conservation and the potential lost revenues from reduced power sales, BPA wholesale rates would creep upward, causing some utilities with perceived lower-cost resource options to purchase power from other suppliers. This action would, in turn, reduce loads placed on BPA and cause its rates to rise even further. A small amount of additional price-induced conservation would be expected as rates increased. As the utilities developed other resources, the need for BPA transmission would likely grow, increasing BPA's transmission revenues and offsetting some portion of the lost power revenues.

BPA Influence

BPA would require all utilities desiring BPA power and transmission services to have a Council-approved least-cost plan that included the implementation of all cost-effective energy conservation. BPA would also institute price incentives such as tiered rates to promote increased energy conservation. Most conservation programs would be utility-designed and -funded. BPA would reduce its spending for incentive programs and direct its efforts at programs such as transfer programs (utility energy conservation savings which are permitted for resale to others without reducing BPA power supply) and R&D energy conservation opportunities. Where these mechanisms did not achieve targeted cost-effective energy savings, BPA would support further incentive programs. To the extent that BPA's transmission and power services costs were below the costs of the utilities' other resource options, utilities would continue to purchase their power requirements from BPA and implement their approved least-cost plans. Where utilities had resource options with costs comparable to BPA's services and the utilities' conservation costs, the utilities would likely take steps to reduce their loads on BPA. The costs and rate impacts from the changes in the resources and associated transmission in this alternative would be similar to those in the Status Quo alternative.

Market-Driven

BPA would continue to pursue the 660 aMW of conservation according to its 1992 Resource Program, by taking its lead from the market and responding with a mix of energy service changes, pricing strategies, and BPA-funded activities. In the long term, pricing strategies might include tiered rates to induce conservation. BPA-funded programs would be tailored to utilities' needs and BPA would become a “seller” of conservation through items such as specially structured loans to utilities. BPA would also fund a small R&D program to identify marketable conservation products. As utilities began to respond to BPA's price signals, BPA could adjust appropriately between pricing and funding efforts to mitigate the rate effects and subsequent load, resource, and transmission responses described in the Status Quo alternative. Where these mechanisms did not achieve targeted cost-effective energy savings, BPA would support further incentive programs.

BPA would engage in regional market transformation efforts designed to bring about lasting efficiency improvements or changes in energy consuming behaviors.

Maximize Financial Returns

BPA would sell its products and services at market value, providing utilities the price signal for doing their own conservation. BPA would fund only conservation that had a proven market and a cost below the near-term marginal rate impact of acquiring the next least-cost resource (presently gas-fired CTs and cogeneration). This would considerably reduce the amount of conservation available to BPA. Conservation R&D would be limited to measures commercially available in the near term and priced below the rate impact of a new resource. Sales of BPA power and transmission products and services would be more important than conservation. BPA rates would remain stable, and utilities would be less likely to leave or reduce load on BPA. Some customers might place more load on BPA, increasing the amount of resources BPA would acquire and the associated transmission it would construct.

Minimal BPA

BPA would not need to acquire conservation because it would not be acquiring any new resources. BPA would stop its current conservation acquisition activities and would buy out or terminate many conservation projects underway. BPA would discontinue conservation R&D efforts. Some customers would likely continue their conservation activities as part of least-cost plans required by state and local regulations. The region would build more generating resources and associated transmission to compensate for the reduction in conservation by BPA. BPA rates would stabilize.

Short-Term Marketing

BPA would acquire only conservation that could be paid for within short-term contracts. This would reduce the amount of conservation achievable. In addition, BPA would market its conservation services and R&D conservation technology. BPA's marketing of conservation services would enhance utility conservation efforts but would lead to relatively small increases in regional conservation because of the lack of additional funding for longer-term measures. BPA would replace the conservation not acquired with spot-market and import purchases. Conservation by the rest of the region would continue, as in the other alternatives, because of state and local regulations. In the near term, BPA rates would stabilize and customer loads would increase.

4.2.3.2 BPA Generation Acquisition

Background

Under the Northwest Power Act, BPA can acquire the output or capability of an electric generating facility, but cannot own the facility. Consistent with the Council's Power Plan, BPA acquires generating resources in order to meet its contractual obligations to supply cost-effective electric power to its customers. BPA's 1992 Resource Program is the planning document that describes the actions BPA will take to meet these power requirements through 2003. The supply of generating resources available to BPA includes renewables (hydro, geothermal, wind, and solar), cogeneration (including solid waste-fired, wood-fired, and natural gas-fired), CTs, coal, and clean coal. The WNP-1 and -3 plants have been terminated and are no longer potential additions to BPA’s power resources. Unless new technology resolves issues such as large unit size, long lead times, non-displaceability, high capital costs, concerns over waste disposal, and public controversy over siting, nuclear energy is not likely to be a part of the region's energy future.

Fuel choice, the decision consumers face when they have options to meet end-use energy needs, affects generating resource acquisitions. Consumers who choose alternate fuels can potentially reduce the load obligations (both peak loads and overall energy requirements) placed on electric utilities. BPA's 1992 Resource Program included an analysis of the choice between electricity and natural gas for residential space and water heating. Although residential fuel choice is the near-term issue, there is a potential for fuel choice to be an issue for commerce and industry in the future.

Location and transmission system integration are important issues associated with generating resource development. Generally, resources located farther from load centers require more transmission. But dispersed generation has the potential to improve the operational efficiency of transmission and distribution systems.

BPA was pursuing about 350 aMW of new generating resources through competitive acquisition and billing credits, plus 1,150 aMW of options through the Resource Contingency Program (RCP). BPA is also pursuing renewable energy resources in the region through the Resource Supply Expansion Program (RSEP). Because of changes in the wholesale power market, BPA is considering terminating those resources that are no longer cost-effective.

Market Response

Status Quo

BPA would have acquired 400 aMW and option 250 aMW of additional resources as specified in the 1992 Resource Program. The output of these resources would be acquired competitively and consistent with the Council’s Power Plan. How the cost of these resources affected BPA's power rates would determine whether customers relied on BPA or pursued other options. To the extent that BPA's power rates were below the cost of the customers' other options, customers would remain with BPA. As BPA's costs approached the cost of the customers' other options, customers would begin pursuing those other options. Under this alternative, BPA likely would overbuild relative to demand. BPA would continue its commitment to the RSEP. Transmission development would be determined by the location of the generating resources selected by BPA and by any transmission needs associated with the customers' other options.

BPA Influence

BPA would require all customers requesting power and transmission services to buy or build generating resources that were consistent with the Council's Power Plan. Because BPA would implement tiered rates, the cost of power from BPA to serve load growth could be above the marginal cost of the customers’ other resource options. Many of BPA’s customers would pursue these other resource options. In addition, under this alternative, many end-use consumers would probably exercise fuel choice and move away from electricity for their energy needs. BPA would acquire fewer resources than under the Status Quo alternative but would still follow the priorities of the Council's Power Plan. BPA would hold options on contingency resources in proportion to firm requirements load. BPA would continue its commitment to the RSEP and thermally matched cogeneration. To the extent that customers planned and acquired resources on the basis of a Council-approved least-cost plan, this alternative would support the one-utility planning concept. Customers not complying with this requirement would be denied the more desirable and lower-cost benefits of BPA's power and transmission system. As in the Status Quo alternative, the amount and type of new transmission would be determined by the location of new generation and by customer requests. As customers reduced the loads placed on BPA, BPA’s rates would rise. Some of this increase would likely be offset by the revenues from transmission services.

Market-Driven

BPA would rely on strategic purchases of short-term energy to meet part of its firm load obligations. Therefore, BPA would acquire fewer generating resources than under the Status Quo alternative, although those resources still would be consistent with the Council’s Power Plan. BPA resource acquisitions could include joint ventures with customers. Additions of CTs would enhance BPA’s ability to supply high-value products and services. Retail curtailment options would add to Federal hydro dispatchability. Despite BPA's competitiveness and diverse marketing efforts, fuel choice would still influence the amount of generating resources BPA acquired. BPA would provide minimal funding of the RSEP to prove the cost-effectiveness of renewable energy resources. Fuel options (gas ventures) would provide for contingencies not covered by short-term purchases. BPA analyzes all planned and existing generation projects and considers terminating those that are more expensive than firm power purchases or new resources. Under this alternative, new transmission would depend more on customer requests than on new resource development by BPA.

Maximize Financial Returns

BPA would focus on near-term resource costs. The agency would import more power because of this focus on low-cost, high-discount resources. Since BPA would pursue only those resources with a high probability of being commercially available in the near term, the RSEP would be smaller than under the Status Quo alternative. BPA would make strategic investments from retained earnings, acquiring only resources that supported a competitive advantage in unbundled markets. In this alternative, some end-users might actually choose electricity over fuels. BPA analyzes all planned and existing generation projects and considers terminating those that are more expensive than firm power purchases or new resources. Because BPA would rely on the market to respond to resource needs, BPA probably would not hold options on generating resources. As a result of the focus on power purchases, BPA would invest in extraregional transmission. Transmission needed to integrate generation would be developed at the request of customers.

Minimal BPA

BPA would allocate current system capability. Therefore, it would acquire no resources beyond those already under construction. Other planned but unbuilt generation projects would be terminated. Because BPA would only allocate existing resources and not meet additional load, the agency would not acquire contingency resources or options. In addition, the RSEP would be discontinued. Because BPA would not develop new resources, it would not develop new transmission.

Short-Term Marketing

BPA would function primarily as a broker, relying on spot-market purchases for up to 5 years to meet firm loads. Long-term acquisitions would be made only if justified based on economic advantage or flexibility. Part of BPA's load would come from consumers changing to electricity to meet some end uses. Funding for the RSEP would be minimal. Options pursued would include “off ramps” to give BPA flexibility. Transmission system development related to new generation would be minimal. Transmission system additions would be planned to secure marketing benefits for BPA.

4.2.3.3 Off-System Purchases

Background

Although BPA resource planning historically has relied on long-term firm power acquisitions to meet forecasted firm loads, interregional system connections facilitate sales of power between systems. These purchases are frequently used to meet near-term operational needs. Deregulation of wholesale electric power markets could stimulate development of generating resources and enable developers to offer power for system sales to BPA or other purchasers. BPA might be better suited than other suppliers to take advantage of off-system purchases due to the storage and shaping capability of the Federal hydro system, which would give BPA more flexibility in timing energy deliveries.

If BPA used more off-system purchases to meet firm power requirements, it could avoid acquiring other firm, long-term energy resources. Resources in other regions would be operated to supply power for BPA purchases. Costs to BPA would depend on the market; if deregulation of the market led to overbuilding of generation among interconnected systems, the price for system sales would likely approach the operating and delivery costs of marginal resources, and might be less than the cost of long-term firm acquisitions. If demand exceeded supply, off-system purchases could be more expensive than firm acquisitions. These costs would lead to rate impacts on BPA's customers and retail consumers. In an uncertain market, a strategy to meet some portion of firm loads with off-system purchases would avoid the risks of long-term commitments, while increasing the cost and supply risks of relying on the market. Transmission capability might limit the extent to which BPA could rely on off-system purchases. Outages, especially on the PNW/PSW Intertie, could interrupt deliveries and require emergency actions to meet BPA loads.

Market Response

Status Quo

BPA would continue to acquire firm resources to meet forecasted firm loads, using off-system purchases to respond to short-term needs and opportunities during the operating year.

BPA Influence

Same as Status Quo.

Market-Driven

Supplying a portion of firm loads with off-system purchases would reduce long-term firm resource acquisitions and shift generation from planned new resources to existing generation in other regions.

Maximize Financial Returns

Similar to Market-Driven, but off-system purchases would be used more, in response to short- or long-term marketing opportunities.

Minimal BPA

BPA firm power obligations would be limited by Federal system capability, so no off-system purchases would be necessary to support those obligations.

Short-Term Marketing

The potentially better match between off-system purchases and the terms and risks of short-term marketing could result in greater reliance on purchases under Short-Term Marketing than under any other alternative. Firm resource acquisitions and related transmission development would be correspondingly reduced.

4.2.3.4 Least-Cost Power Resource Planning

Background

The two most influential factors in least-cost power resource planning are environmental costs and the discount rate. Variations in the values of these factors can alter priorities among resource types, and change the composition of the supplier's resource portfolio. Environmental costs particularly add to the costs of combustion-type energy resources. Fossil fuels also have environmental costs related to extraction. Of major concern with these energy technologies is carbon dioxide and its relation to global warming. Where environmental costs are given greater weight, any cost advantage held by fossil fuel and combustion resources over energy efficiency and renewable resources tends to be diminished.

The discount rate applied in calculating the costs of resources can also alter the relative costs of different resource types.[2] A low discount rate favors capital-intensive resources, while a high discount rate favors

[2] The discount rate indicates the purchaser's perception of the future value of a present cost. A high discount rate means that the purchaser believes future value declines rapidly; a low discount rate means that the purchaser believes the value of the item extends farther into the future.

resources with low financing costs and relatively higher operating costs. In the current market for energy resources, a low discount rate favors energy conservation and renewable resources, while a high discount rate favors CTs.

Where, as in the BPA Influence alternative, a least-cost standard is a condition of service, the degree of consensus on environmental cost and discount rate incorporated into that standard will contribute significantly to the customer's willingness to conform to such conditions. The less the customer agrees with the values of the required standard, the more likely it is that the customer will choose to purchase power services from suppliers who do not attach such conditions to service.

Market Response

Status Quo

BPA resource acquisitions would conform to the Council's direction on least-cost planning. Regulated utilities would be subject to least-cost requirements of public utility commissions. For resources that fall under state siting processes, resource developers also would be subject to least-cost planning requirements of siting authorities. Customers' decisions on whether to purchase power services from non-BPA suppliers would not be significantly affected by BPA's assumptions on least-cost planning conditions.

BPA Influence

Council-approved least-cost plans would be a condition for unbundled services and other BPA service flexibility. Surcharges would apply to BPA services to customers without approved plans. BPA would apply conditions to all customer resource acquisitions, including resources developed by unregulated utilities and outside of the control of state siting authorities. Customers developing or acquiring resources inconsistent with Council direction would pay surcharges, and might take steps to meet all power service needs (existing loads and load growth) without BPA services.

Market-Driven

Same as Status Quo.

Maximize Financial Returns

BPA least-cost planning would be more heavily weighted by near-term monetary costs; environmental costs would be considered as a decision factor. BPA would develop fewer conservation and renewable resources. Customer resource development decisions would be made on the same basis as under Status Quo.

Minimal BPA

BPA would not develop resources. Customer resource development decisions would be made on the same basis as under Status Quo.

Short-Term Marketing

The short-term marketing focus would result in few BPA long-term acquisitions. BPA resource development would be consistent with Council direction, but power purchases would replace most conventional resource acquisitions. Customer resource development would be the same as under Status Quo.

4.2.4 Transmission

4.2.4.1 Transmission System Development

Background

BPA transmission system development is driven by several factors. The BPA Reliability Criteria for System Planning (Criteria) are the rules that determine the capacity the system must provide to maintain continuity and quality of service to electrical loads during certain more common system disturbances. The aim is to ensure cost-effective reliability for the electricity consumer. The Criteria are well defined and are applied uniformly across the system. They have been developed in cooperation with the public, and the reliability levels provided are largely determined by public input. The Criteria and the focus on continuity of service to load are major drivers of internal grid development.

In the future, EPA-92 may influence transmission development. The statute provides that FERC may order any transmitting utility to provide transmission service, and to construct new facilities if necessary to provide such service. The effect of this statute, which may lead to additional transmission system development, applies to all the alternatives described below.

BPA does not have its own formal, detailed criteria that specify the level of transmission reliability that must be provided for BPA economy transactions, wheeling for others, or resource-integration; however, the agency must adhere to WSCC criteria governing these services. These functions normally do not directly affect continuity of service to load. Reliability requirements are generally determined on a case-by-case basis and may involve internal network or intertie development. Economy transactions, resource integration, and wheeling are virtually the sole drivers of intertie development and are also significant for internal grid development.

A public review of the Reliability Criteria for System Planning is now underway. It is likely that any resulting revisions to the Criteria could be common to all of the following alternative business approaches. Based on the results of the last review of the planning criteria in 1989 and developments since then, it is unlikely that the public will call for increased reliability at the cost of increased rates. If reliability were lowered, there would be less need for transmission system expansion. Line and substation construction would be reduced, and overall transmission system costs would decline. System outage severity and service interruptions to some customers would increase. The degree of decrease in service level would depend on the level of reliability provided.

As part of the Criteria review, BPA plans to discuss the development of reliability criteria for economy transactions, wheeling, resource integration, and interties. These criteria, if developed, or the ad-hoc approach to these services, could vary among the alternatives.

Market Response

Status Quo

BPA would continue to plan and construct transmission as it does now; that is, with a long-term, one-utility focus and defined reliability criteria that result in a high level of system-wide reliability. Transmission system expansion plans and associated budgets and construction activity would be about the same as in the recent past when averaged over several years. Year-to-year variations in expansion plans could continue to be significant because system problems occur randomly and because transmission capacity is added in large blocks. System outage rates and severity and service interruptions for consumers would remain about the same as at present.

Good-faith requests or FERC-ordered transmission service for non-utility generators and utilities pursuant to EPA-92 might lead to some increase in BPA transmission development. Because this development would be intended to expand service while maintaining existing transmission system reliability, outage rates and severity would be about the same and consumers would see no significant change in frequency and duration of outages.

If the public were to make a strong call for a substantial change in the BPA Reliability Criteria, it would be difficult to justify continuing to plan transmission system development using existing criteria, especially if the call were for lower reliability to hold down system costs. (BPA would still need to follow Northwest Power Pool, WSCC, and North American Reliability Council reliability criteria.)

BPA Influence

BPA would continue to plan and develop its transmission system as under the Status Quo alternative; however, as described under Transmission Access, priority would be given to utilities that comply with the Council's Power Plan and F&W Program. Within the constraints of EPA-92, shaping transmission services to include integration of resources, and wheeling to promote compliance with the Plan and Program, could either increase or decrease system development compared to present levels. The influence would likely depend on specific situations and might have no significant overall effect on system development.

Market Driven

BPA would follow the public's guidance in setting appropriate levels of transmission system reliability and risks associated with system development decisions (still bearing in mind the need to abide by WSCC and other reliability criteria). At this time, it is not known whether the public would want to change current reliability levels after review of the planning criteria now underway.

BPA could also offer unbundled reliability levels where practical. BPA could offer different levels of priority for interruption of service when necessary to relieve a transmission system problem (e.g., transmission over a constrained transmission path). Interruption of service is an alternative to reinforcing the system to maintain the service. The average overall level of system reliability could shift up or down depending on whether, on balance, individual customers called for higher or lower reliability. The net effect would likely be lower reliability, which would reduce the need for new transmission line and substation construction. System outages would be more severe, but service interruptions would increase only for those utility customers that opted for lower reliability (and lower rates) for such service.

Unbundling could affect either service to loads or wheeling. Interrupting load could lead to scheduled or unscheduled brown-outs or black-outs of electrical service. To interrupt wheeling requires adjustments or dropping of schedules or generation; however if generation reserves were adequate, all loads would continue to be served. Some parties would experience higher production costs and other economic consequences.

With both unbundling and a public call for reduced reliability overall, service interruptions might increase for all utility customers, but would increase more for those that opted for lower reliability.

Maximize Financial Returns

BPA would maximize returns from existing transmission facilities. BPA would probably "squeeze" the transmission system as hard as possible by minimizing development and promoting maximum use of the system. BPA might consider selling facilities when receipts from the sale would exceed the expected net value of future revenues provided by the facilities.

System reliability could be reduced to the point where BPA would begin to lose profitable business, captive customers would press BPA to improve service, or FERC, pursuant to EPA-92, might order BPA to provide transmission service and to add capacity to do so. With curtailed development, there would be less need for transmission line and substation construction. With lower reliability, system outage severity and service interruptions to customers would increase.

This alternative suggests an inherent short-term approach to business planning. Risks under this option would vary, depending on how much flexibility and margin BPA would build into the system to take advantage of future business opportunities and to protect against reliability problems. BPA could choose to build only when a profitable, confirmed, and near-term opportunity to provide service or to access a power market were identified. Financial risk under this approach would be loss of business opportunities that occur quickly and that require new transmission capacity to access. Lead time on major new transmission might be 6 or 7 years. Providing absolute minimum facilities for reliability, especially if the criteria were revised downward as a result of the present review, offers no margin for long-term catastrophic loss of facilities such as might occur to transmission lines in mountain passes or from an earthquake.

If BPA chose to provide system capacity margin, BPA would be better able to take advantage of future unanticipated business opportunities and maintain reliability in the event of major system problems. The risk would be that the investment in margin might not pay back if the potential business opportunities or system problems did not occur.

This approach would not provide much incentive for BPA to pursue regional one-utility planning. What is best for BPA maximum profit might not be best for the region. However, FERC orders pursuant to EPA-92 and the new Regional Transmission Groups (RTGs) for regional and western transmission planning might push the region in the direction of more optimal transmission system development.

Minimal BPA

BPA would freeze its system development, and, because it would have withdrawn from the competitive market, system development would likely be assumed by others. Over the long term, BPA would effectively give up control of system reliability to other parties. This would have unknown effects on transmission construction and reliability of service to consumers. If regional transmission planning became disjointed and competitive, future development might become duplicative and non-optimum, or inadequate. This might not occur if RTGs now forming effectively foster regional coordinated transmission planning.

Even with development frozen, BPA would remain a major provider of transmission for the region for a long time because it now owns about three-fourths of the region's transmission capacity. This option would preclude BPA's serving as the provider of new transmission *facilities* for the region, but BPA might still be able to provide new transmission *services*. For example, existing committed capacity could become available for new business if old customers departed or BPA were willing and able to avoid renewing uneconomical contracts for serving loads or wheeling services.

Short-Term Marketing

BPA would phase out long-term contracts and market new power and transmission services only on a short-term basis. There would be virtually no incentive to build new transmission. Major transmission investments have long payback periods and require long-term sales commitments to recover costs. Unless a long-term stream of profitable short-term sales were assured, major transmission investments would be too risky. As a result, BPA probably would not construct discretionary transmission facilities. Regional transmission development likely would follow the course described under the Minimal BPA alternative.

4.2.4.2 Transmission Access

Background

BPA's transmission system was constructed primarily to deliver power from the FCRPS to the customers that purchase power from BPA. As provided by statute, BPA provides other utilities access to transmission capacity as available. EPA-92 gives FERC the authority to order BPA to provide wheeling services to eligible requesting entities, which can include utilities and non-utility generators.

Market Response

BPA Influence

BPA would provide priority transmission access to utilities and resources that comply with the Council’s Power Plan and F&W Program. Although EPA-92 includes a “public interest” standard for FERC review of requests for transmission service, it is not clear whether such priorities would be acceptable to FERC in a dispute regarding access provisions of EPA-92. In such case, it is not clear that there would be any long-term effect with such priorities, as FERC might also require utilities to add transmission capacity if necessary to respond to orders for transmission service. Therefore, while in the short run BPA may provide priority access to resources and utilities that comply with the Council’s Power Plan and F&W Program, in the long run, BPA could be obliged to construct additional transmission capacity as necessary to serve all parties. BPA would not provide wheeling for resources that violated the Council's Protected Areas Rule.

Market-Driven

BPA would treat non-Federal wheeling loads comparably to Federal power loads, and would not use its dominant share of the transmission system to the disadvantage of any of its competitors in serving regional utility loads. In case of transmission constraints, transmission to regional loads would have priority over transmission to extraregional loads. BPA would expect reciprocal treatment from other transmission providers, to the extent allowable by applicable law or FERC requirements. BPA would not provide wheeling for those resources within the Columbia River Basin that violated the Council's Protected Areas Rule.

Short-Term Marketing

BPA would reallocate transmission capacity when current contracts expire; new contracts would be short-term (less than 5 years), to the extent not ordered otherwise by FERC pursuant to EPA-92. Because these contracts would provide no long-term certainty of transmission access, efficient transmission and resource planning and development would be frustrated. There might be a trend to construct new transmission facilities that duplicate some of the paths of existing BPA transmission; alternatively, more generation might be located closer to loads, and integrated by means of transmission lines constructed by parties other than BPA.

Status Quo, Maximize Financial Returns, and Minimal BPA

In all other alternatives, BPA would provide short- and long-term access to surplus transmission capacity on a non-discriminatory basis. BPA currently provides access to surplus transmission capacity to utilities; EPA-92 also supports access by other entities, such as IPPs. Such access provisions should support efficient development of transmission and generation. By reducing barriers to transmission access, and by including non-utility generators among entities that may request access, EPA-92 supports increased efficiency in transmission and generation planning and development. EPA-92 might cause some of BPA's customers to purchase more of their power requirements from sources other than BPA. EPA-92 prohibits FERC from ordering wheeling to serve retail loads (although it does not prohibit such wheeling on a voluntary basis); therefore, EPA-92 should have no direct effect on utility retail loads.

4.2.4.3 Assignability of Rights Under BPA Wheeling Contracts

Background

BPA's wheeling contracts are currently written to provide specified services for specific wheeling customers for specific periods of time. BPA's wheeling customers have expressed interest in having the right to reassign wheeling contracts to third parties or to use the contract to wheel for third parties (third-party wheeling).

Market Response

Status Quo

BPA would continue restrictions against reassigning wheeling contracts and third-party wheeling. Some transmission capacity would go unused during periods when the utility holding the wheeling contract could not use it, and administrative or rate barriers would prevent BPA from making the capacity available to others.

BPA Influence

BPA would allow wheeling rights to be transferred, but discounted or priority service could be assigned only to customers that comply with the Council's Power Plan and F&W Program. To the extent that being able to transfer wheeling rights provides an economic incentive large enough to influence resource acquisition choices, the provision could encourage customers to use long-term least-cost resource planning and to comply with the goals of the Council's F&W Program.

Market-Driven

BPA would allow wheeling customers to reassign their wheeling contracts to third parties or to wheel for third parties. The party receiving the wheeling right would receive no greater transmission rights than the original party (e.g., if the original transmission right were on a specific transmission path, rights to the same transmission path only could be reassigned). BPA would suffer no substantial revenue loss. Under existing circumstances, BPA wheeling customers typically pay a demand and energy charge; if they are not using their full-capacity right, they continue to pay the demand charge, but not the energy charge. In that case, BPA attempts to "fill up" the unused capacity with nonfirm transmission services, for which it charges nonfirm rates. If BPA allowed third-party wheeling and reassignment, BPA might more often receive the firm capacity demand *and* energy charges. It is possible that allowing reassignment would mean that the BPA transmission system would be operated at higher load factors (i.e., closer to "full capacity"), but doing so would provide additional flexibility in the use of the BPA transmission system and would foster increased efficiency in the operation and development of generation resources. Overall, fewer generation and transmission resources might be developed.

Maximize Financial Returns

BPA would not allow wheeling contracts to be reassigned, but would instead aim to maintain strategic control over the transmission network (to the extent allowed under EPA-92). Transmission and generation development might not be as efficient as under the Market-Driven BPA alternative.

Minimal BPA, Short-Term Marketing

In these alternatives, BPA would allow wheeling rights to be transferred to third parties. In the **Minimal BPA** alternative, transfer rights would be part of long-term wheeling contracts using BPA's existing transmission capacity. Allowing reassignment could help BPA's limited transmission capacity to be used more efficiently as loads grew and the regional power transmission network grew without BPA's participation. In the **Short-Term Marketing** alternative, BPA would offer wheeling contracts only of less than 5 years' duration, but wheeling rights could be reassigned. Even on this short-term basis, reassignment could provide flexibility that could increase system efficiency.

4.2.4.4 Retail or DSI Wheeling

Background

Currently, the principal end-use consumers served directly by BPA are the DSIs. (BPA also serves some Federal agencies.) For a variety of reasons, the DSIs have been exploring options for power service, both for part or all of their existing loads and for new loads associated with future expansions. In most cases, BPA would have to provide wheeling over its transmission system in order for other suppliers to serve the DSIs. In the past, BPA has not wheeled power to DSIs, except for Industrial Replacement Energy (IRE); however, BPA believes that it is authorized to do so by the Federal Columbia River Transmission System Act. There is nothing in EPA-92 that would prevent BPA from voluntarily providing wheeling service to other retail loads.

Market Response

Status Quo

BPA would continue its current policy of not providing long-term wheeling for the DSIs. The DSIs would have to continue to rely on BPA to serve their loads. Given the language in EPA-92 regarding retail wheeling, it is unlikely that FERC could require BPA to provide access over its transmission system for other utilities or non-utility generators seeking to serve DSI loads. It is possible, however, that a DSI could become a customer of its local utility, which might then purchase power on the market for the DSI. Failing this, the DSI loads would continue to be a major BPA contract load, and the economic factors that influence the amount of their load on BPA would continue to lead to significant uncertainties in BPA's power sales revenues.

BPA Influence

BPA would provide wheeling to DSIs, but only for resources owned by utilities that complied with the Council's Power Plan and F&W Program. Adding such a policy requirement could support long-term least-cost power planning and fish and wildlife enhancement, and would essentially continue the status quo regarding the types of resources that would serve DSI loads; that is, DSIs would either be served by BPA (which would comply with the Plan and Program) or by utilities or other entities that complied with the Plan and Program in order to receive wheeling services from BPA.

Market-Driven

BPA would provide wheeling to DSI loads, but not to other retail loads. In cases where DSIs needed wheeling services from an intervening utility or other suppliers in addition to services from BPA, BPA would act as the DSIs' agent, and contract directly with the intervening utility for the wheeling service. Providing wheeling to DSIs would increase the DSI customers' power options, and therefore potentially could reduce the amount of load for which BPA would have to acquire resources in the future. Providing wheeling to DSI loads could mean the loss of some Federal power sales revenue, but it would also reduce the revenue uncertainty associated with the relatively volatile DSI loads. Providing wheeling to DSIs would likely be an incentive for IPPs or other utilities to develop CTs, because DSIs could firm nonfirm power by using displaceable CTs to back up purchases of nonfirm power from BPA or other utilities.

Maximize Financial Returns

BPA would provide wheeling to serve DSI loads and to serve other retail loads where doing so would be financially beneficial and legally feasible. As noted above, EPA-92 leaves regulation of retail wheeling to state and local governments. Currently, most states restrict wheeling to end-use customers by establishing utility franchises, which are generally defined on a geographic basis. However, this might change in the future. Wheeling to retail loads other than DSIs could require construction of delivery and/or transmission facilities. In this alternative, BPA would provide such services where the wheeling revenues to be earned would exceed the costs of new and existing facilities required to make the delivery. Assuming that legal and facility obstacles were overcome, BPA's provision of wheeling to end-users other than DSIs could introduce a new degree of competition for power supplies that could put some downward pressure on generation supply costs. On the other hand, retail wheeling could also introduce considerable uncertainty into regional utility planning. Generation and resource investments of the utility losing the retail load could be stranded, and the development of conservation and other resources on the basis of long-term least cost could be hindered.

Minimal BPA

BPA would acquire no new generation resources. BPA would allow wheeling only to utilities serving areas where DSI loads are located to the extent capacity was available over existing facilities (where legally feasible and financially beneficial). The market responses would be as described above for the Maximize Financial Returns alternative.

Short-Term Marketing

BPA would market power only under short-term (less than 5-year) contracts. BPA would allow wheeling to DSI and retail loads to provide customers access to long-term power sources. The market responses would be as described above for the Maximize Financial Returns alternative.

4.2.4.5 Customer Service Policy and Subtransmission Facilities

Background

BPA's CSP divides responsibilities between BPA and its customer utilities for planning, construction, maintenance, and allocation of costs associated with facilities needed to deliver Federal power from BPA to customers. The current CSP, most recently comprehensively revised in 1984, states that BPA is responsible for constructing and financing transmission facilities (115-kV and higher voltage), and generally delivers power at the prevailing transmission voltage (normally at least 115 kV, but in some cases 69 kV). The CSP also states: “BPA will be financially responsible for providing a limited amount of capacity for deliveries at distribution voltage level for small power sales customers.” This means that BPA provides 50 MVA of distribution transformation capacity for utilities with under 25 MW average load. BPA does not impose extra charges to provide subtransmission delivery facilities for those customers that qualify for such facilities under the CSP. Facilities are planned and constructed on the basis of long-range joint planning studies based on the one-utility concept.

Market Response

Status Quo

The existing CSP would continue to shape BPA's planning, construction, and cost-sharing of facilities to deliver electrical energy to customers.

BPA Influence

BPA would add a new condition to the CSP—BPA would provide “one-utility”-type facilities (including delivery facilities to small power sales customers) only if the customer complied with the Council's Power Plan and F&W Program. For other customers, BPA would add facilities only to the extent that they served the needs of BPA and those of its customers that complied with the Plan and Program. For BPA's customers that do not own or operate generation (generally its smaller customers), this provision would have little meaning (presumably they would comply with the Plan and Program). For customers that do own and/or operate generation resources, and that do not comply with the Plan and Program, this restriction on BPA's provision of transmission and delivery facilities could force those utilities to comply (i.e., to divest themselves of noncomplying resources or cease non-compliant practices or operations). Alternatively, it could drive them to develop their own facilities. In the latter case, transmission development would depart from the one-utility model, and would therefore occur less efficiently.

Market-Driven

BPA would narrow its role to providing bulk power transmission to its power customers. Subtransmission facilities (i.e., fringe and delivery segments) and new substation facilities would increasingly be the responsibility of the customer utilities. BPA would develop a feasibility test (based on what makes good business sense from BPA's perspective) that would be used to determine the extent of BPA's participation in the development of new delivery and transfer arrangements. BPA would charge a wholesale power rate surcharge for those customers not taking power at prevailing voltage levels (i.e., voltage used for bulk power transmission in the locality served), in order to encourage customers to purchase and operate existing BPA delivery substations and associated facilities. Customers could avoid the rate surcharge by owning delivery facilities serving their loads. At jointly owned substations, BPA contracts would require cost-sharing for hazardous waste prevention and clean-up.

This alternative would primarily affect which parties pay the costs of subtransmission facilities rather than the kinds of facilities constructed. It would reduce costs associated with BPA's most basic power service (delivery of power at transmission voltages), and send a price signal that reflects the cost of providing subtransmission services. In turn, this could lead to reductions in the price of the basic service.

Customer utilities for which BPA now provides subtransmission facilities might face significant new capital and operations costs. Low-density utility customers of BPA might pay more per unit of energy delivered as they assume more of the costs of subtransmission facilities. For some utilities, the capital and operations costs of subtransmission facilities might be great enough that utility take-overs or consolidations might occur.

This alternative would affect the types and locations of new subtransmission facilities only to the extent that customers who build their own facilities do not use the one-utility planning concept that BPA currently uses under its CSP. In that case, subtransmission facilities might be constructed less efficiently and therefore would have greater environmental impacts (see section 4.3) than would be the case under the Status Quo alternative. However, it could also be argued that by sending more direct price signals to customers about the cost of developing new subtransmission facilities, subtransmission planning would occur more efficiently. It is not likely that this alternative would have a substantial effect on the location and capacity of transmission facilities, which would continue to be planned and constructed by BPA on a long-term, one-utility basis (except as modified by requests for access made pursuant to EPA-92).

Maximize Financial Returns

BPA would provide only bulk transmission service, and would price all subtransmission services at the incremental costs of the facilities required to provide the service. If subtransmission services required long tap lines or other facilities that were expensive in relation to the load served, the price charged for subtransmission services could be substantial. If the incremental costs could not be recovered from rates, BPA would not construct the facilities. The impacts on smaller and low-density customers would be similar in nature to those of the Market Driven alternative.

Minimal BPA

BPA would construct no new subtransmission or distribution facilities and would no longer maintain or replace facilities at voltages lower than the local transmission voltage. All BPA customers would have to develop their own facilities to meet any incremental load growth not served by their allocation of BPA power. For small customers, increasing shares of the costs of subtransmission and distribution could raise these utilities' cost of service, perhaps causing them to increase their rates. For larger utilities that already provide most of their own subtransmission and distribution facilities, this change would have proportionately less effect on their cost of service and rates.

Short-Term Marketing

BPA would construct no new subtransmission or distribution facilities once the existing power sales contracts expire. Market responses would be similar to those of the Minimal BPA alternative.

4.2.4.6 Operations, Maintenance, and Replacement

Background

Alternative priority-setting schemes for transmission system maintenance and replacement would affect how outage risks are distributed among customers. Customers served by facilities with higher priority for maintenance would experience fewer and shorter outages than customers served by lower-priority facilities. Outages would be more likely if necessary maintenance activities could not be sustained by available funds. Constricted budgets increase the potential that BPA would be unable to meet all maintenance needs.

The effect of outages would depend on the capabilities and options available to the customer. For those facilities with lower priority for BPA-supplied maintenance, BPA could transfer ownership, along with responsibility for maintenance, to the customer, or arrange for the customer to perform maintenance on those facilities. Another option would be for the customer to reduce reliance on low-priority facilities by arranging for load-shedding measures, acquiring reserve power supplies to substitute for service lost to outages, or constructing additional transmission facilities. Finally, a customer could choose to abandon BPA service, either by substituting service from another supplier, or by developing generation and reserves that eliminate reliance on BPA facilities.

For customers without financial or technical resources to construct or maintain their own facilities, the effects of outages on low-priority facilities would be passed along to consumers. At the retail level, some consumers might be able to mitigate the impacts of outages—for example, by using backup generation. Others would have to bear the costs of outages. For some consumers, such as commercial or industrial enterprises, outage costs might determine the viability of the business, so that longer or more frequent outages would cause the consumer to cease operation. As a result, loads served by customers with lower priority for maintenance could decline.

Market Response

Status Quo

Maintenance based on the length of time facilities are in service would place risk of outages more with facilities receiving intensive use. Assuming intensive use occurs more in high load and high load-growth areas, outage risks could be higher in those areas compared to other areas.

BPA Influence

Maintenance priority based on compliance with regional plans would place increased risk of outages on customers failing to comply with those plans, to the extent possible in an interconnected system, providing an additional incentive for compliance.

Market-Driven

BPA's maintenance priorities would be set according to outage duration and frequency criteria. Risk of outages should be fairly uniformly distributed over BPA's facilities in the long run, as the “trailing edge” of facilities performance is brought up to standards.

Maximize Financial Returns

Priority to facilities producing the most revenue would place risk of outages increasingly on facilities serving small loads or areas of low load-growth rates.

Minimal BPA

Same as Status Quo.

Short-Term Marketing

Same as Market-Driven.

Table 4.2-1: General Market Responses to Issues

Issue	Resource Development	Resource Operation	Transmission Development	Transmission Operation	Consumer Behavior
PRODUCTS AND SERVICES					
Bundling or Unbundling of BPA Power Products and Services	Unbundling encourages efficient use of BPA power products and might stimulate the market for separate power services; might add to resource development cost.	Unbundled services might provide an incentive for resource owners to provide separate services from their own facilities.	Resource development to supply unbundled power services might increase the need for transmission facilities.	Unbundling promotes more efficient use of power system facilities, such as operation at higher load factors.	Redistribution of costs among BPA customers with unbundling might shift BPA costs, increasing some consumers' costs and reducing costs for others.
Surplus Products and Services	Long-term BPA firm export sales might shift resource development toward BPA, emphasizing resources that complement Federal hydro power.	Export purchasers might operate resources differently with long-term BPA surplus products.	BPA might participate in transmission development to enhance surplus marketing.	No significant effect; the system would operate to deliver from all resources and to all loads.	Revenues from surplus sales might have a minor effect on costs at the retail level.
Scope of BPA Sales	Wider sales would increase BPA loads, increasing BPA resource needs or reducing surpluses.	BPA sales could displace others' resources, changing operations.	Little or no change.	Little or no change.	Might reduce costs to consumers served by new BPA customers.
Determination of BPA Firm Loads	Broad definition would increase BPA loads, increasing BPA resource needs or reducing surpluses.	Operations would respond to availability and pricing of BPA services, as with unbundling.	Little or no change.	Resale transactions could shift transmission use among customers.	Might reduce costs to consumers served by new BPA customers.
Marketing to Support System Stability and Power Quality	Availability of lower-quality service could reduce new resource needs by fuller use of existing resources.	Resource owners could operate to compensate for choice of lower-quality BPA service.	Lower-quality service could reduce new facility needs by fuller use of existing facilities. Charges for burdensome loads could reduce need for compensating facilities.	Greater use of nonfirm capability could increase use of facilities and raise load factors. Charges for loads that burden the system could reduce the need for operations to accommodate those loads.	Might reduce power costs to consumers served by utilities selecting lower-quality service. Specific loads could face increased costs for reactive loads or harmonics. Consequences would depend on the consumer's circumstances.
Unbundling of Transmission and Wheeling Services	Distance-based costs could discourage remote resource siting. Priority service could influence resource choices.	Little or no change.	Unbundling might reduce demand for some services, lessening the need for new facilities.	Unbundling might reshape current uses.	Redistribution of costs with products could reduce loads of consumers served by transmission-intensive utilities.

Table 4.2-1 (continued): General Market Responses to Issues

Issue	Resource Development	Resource Operation	Transmission Development	Transmission Operation	Consumer Behavior
PRODUCTS AND SERVICES (CONTINUED)					
Other BPA Services	Revenue could reduce BPA loads shifting to non-BPA suppliers, increasing BPA resource needs or reducing surpluses.	Little or no change.	Little or no change.	Little or no change.	Lower BPA power costs could result in increased demand.
PRICING					
Power Pricing and Rate Attributes	Total costs under tiered rates and other rate features might influence customers' choice of power supplier.	Total power costs might influence operations by resource owners.	Little or no change.	Changes in load shape due to power pricing could shift timing or location of transmission use.	Wholesale power costs would affect loads to the extent costs are reflected in retail rates.
Transmission and Wheeling Pricing	Price levels and incentives could influence resource choice or location.	Little or no change.	Pricing for more efficient use of the system could reduce the need for new facilities.	More efficient use in response to pricing might shift timing or location of use.	Pricing could reduce loads of consumers served by transmission-intensive utilities.
ENERGY RESOURCES					
BPA Conservation	Conservation achieved would be influenced by the extent and form of BPA investment.	Little or no change.	Need for transmission facilities would be affected by load reductions from conservation.	Little or no change.	Consumers might benefit from conservation programs or adopt measures in response to price.
BPA Generation Acquisition	BPA acquisitions could lead to surplus, displacing other resource acquisitions.	BPA short-term purchases could increase operation of sellers' resources.	Customer choice of supplier could shift need for transmission facilities.	Little or no change.	Little or no change.
Off-System Purchases	Off-system purchases would reduce need for new resources.	Little or no change.	Little or no change.	Little or no change.	Little or no change.
Least-Cost Planning	If required least-cost planning should vary from near-term economic choices, resources selected might be altered by least-cost requirement.	Little or no change.	Transmission needs might change if least-cost planning results in a different mix of resources.	Little or no change.	Consumers might be affected if least-cost planning increases development of demand-side management.
TRANSMISSION					
Assignability of Rights under BPA Wheeling Contracts	Assignability could expedite wheeling, facilitating resource development.	Little or no change.	Assignability could lessen need for new facilities.	Assignability could intensify use of existing rights, increasing load factor.	Little or no change.
Transmission System Development	Additions for reliability or to provide access might facilitate resource development.	Little or no change.	Reliability criteria and planning would set direction for regional system.	Operations would adjust to new facilities.	Revised reliability standards might modify service to consumers.

Table 4.2-1 (continued): General Market Responses to Issues

Issue	Resource Development	Resource Operation	Transmission Development	Transmission Operation	Consumer Behavior
TRANSMISSION (CONTINUED)					
Transmission Access	Priority for transmission access might affect resource choice.	Little or no change.	Access requests would influence system additions.	Service for requested access might change use.	Little or no change.
Retail or DSI Wheeling	DSI wheeling could increase DSI generation develop-ment to serve existing load and load growth. Retail wheeling would reduce utility loads and resource needs, and increase nonutility resource development.	Change in utility loads from retail wheeling might change resource operations. Major load losses to utilities could lead to generation shutdowns.	Increased resource development for DSIs or retail loads might affect the need for new transmission facilities.	Little or no change.	Consumers wheeling resources would respond to market prices rather than utility rates in deciding on efficiency measures.
Customer Service Policy and Subtransmission	Little or no change.	Little or no change.	Would affect facility development criteria and the extent of BPA development.	Little or no change.	Charges could redistribute costs among BPA customers, raising some consumers' costs, reducing costs for others.
Operations, Maintenance, and Replacement (OM&R)	Little or no change.	Little or no change.	OM&R direction might affect the need for new facilities.	Would affect maintenance costs, capability of facilities.	Might affect quality of service locally and related costs.

4.3 Generic Environmental Impacts

Section 4.4 of this EIS identifies environmental impacts and market responses to each Business Plan alternative. The market responses generally take the form of changes in generation and conservation development and operation, transmission development and operation, and consumer behavior.

This section prepares the reader for that discussion by describing *typical* environmental impacts of the market responses.

4.3.1 Resource Development and Operation

Typical impacts associated with the development and operation of generation and conservation resources were described in the Resource Programs Final EIS (DOE/EIS-0162, February 1993). New resources that might be developed and operated in the region in response to Business Plan alternatives are likely to be among the resource types described in that document. Table 4.3-1 summarizes information from the Resource Programs Final EIS on the typical environmental impacts per average megawatt of different generation and conservation resources. Figure 4.3-1 summarizes the nature of environmental impacts of various resource types. The Resource Programs Final EIS provides additional information about the nature of these impacts and typical mitigation measures taken to reduce or eliminate them. Figure 4.3-2 shows the level of key environmental impacts by resource type.

The key environmental impacts of energy resource types that are likely to serve the PNW are summarized below:

Conservation typically has minimal environmental impacts. The primary concern for many residential conservation programs—indoor air quality (IAQ)—can be effectively mitigated through a variety of means built into most residential conservation programs. Conservation programs in other sectors have few environmental impacts that need specific mitigation.

Renewable Energy Resources vary considerably in their environmental impacts. Geothermal energy's major environmental impacts are contaminants from geothermal steam (particularly hydrogen sulfide), waste heat, degradation of water quality, and solid waste. However, these impacts are very site-specific, and mitigation measures can minimize most of them. Large-scale solar energy projects can occupy large areas of land and require water for cooling. The primary concerns for wind energy stem from the significant land use requirements of large-scale wind energy facilities, and associated visual impacts. New hydroelectric projects can vary considerably in size and impacts. Environmental concerns include the alteration of surface water and stream habitat. Water temperature, water quality, stream flow, fish migration, and wildlife habitat may be affected.

Cogeneration involves the simultaneous production of heat for industrial uses and electricity. A variety of fuel types, including natural gas, coal, and biomass can be used for cogeneration; however, natural gas is becoming the fuel of choice and is assumed to be the fuel for the cogeneration projects discussed in this EIS. Impacts are typically similar to CTs; however, most cogeneration projects are located in existing industrial sites. Therefore, impacts on other land uses are limited. New cogeneration often replaces older boilers with higher air emissions, leading to a net reduction in air emissions and no new land use impacts.

Combustion Turbines are rapidly evolving in response to increased gas supplies, lower gas costs and increased energy efficiency of CTs. CTs are typically fueled by natural gas. A major concern for CTs has been air emissions, particularly nitrogen oxide (NO_X). However, NO_X emission rates of CTs recently proposed in the PNW are considerably lower than those of CTs proposed even 2 to 5 years ago, in some cases decreasing by two-thirds.

Table 4.3-1
Typical Environmental Impacts From Power Generation and Transmission(a) (b) (metric units)

Conservation and Generation	SO2 (ton/aMW)	NOx (ton/aMW)	CO2 (ton/aMW)	Particulates (ton/aMW)	CO (ton/aMW)	Consumed (m3/aMW)	Consumed (ha/aMW)	Discharge (mill. Joules/aMW)
Conservation	0.00	0.00	0	0.00	0.00	0	0.00	
Efficiency Improvements	0.00	0.00	0	0.00	0.00	0	0.00	
Renewables								
Geothermal (c)	0.80	0.00	636	0.00	0.00	55,260	0.11	138,205,000
Solar	0.00	0.00	0	0.00	0.00	481	2.43	24,265,000
Wind	0.00	0.00	0	0.00	0.00	0	9.55	
Hydro	0.00	0.00	0	0.00	0.00	0	0.00	
Cogeneration								
Solid Waste-Fired	13.63	70.18	13,256	3.00	2.69	0	0.81	
Wood-Fired	0.52	9.02	11,959	1.71	16.96	66,978	1.06	
Existing Natural Gas-Fired	0.03	5.27	3,542	0.03	2.02	4,194	0.06	30,384,000
Older Natural Gas Combustion Turbine	0.03	5.27	3,542	0.03	2.02	4,194	0.06	
Newer Natural Gas Combustion Turbine (d)	0.01	0.42	3,313	0.15	0.61	4,194	0.06	
Nuclear	0.00	0.00	0	0.00	0.00	19,736	0.91	44,310,000
Coal	8.63	21.56	8,843	1.30	1.53	13,186	0.54	44,310,000
Clean Coal								
Fluidized-Bed Coal	3.14	5.26	8,052	0.59	1.40	20,266	0.64	
Gasification Coal	1.47	3.86	7,551	0.24	0.14	20,056	0.30	
Fuel Switching (e)	0.00	2.27	2,550	0.03	1.07	0	0.00	
Power Purchases (f)	0.03	5.27	3,542	0.03	2.02	4,194	0.06	
Aluminum Smelter	1.06	0.01	335	1.77	64.34	13,545	0.00	1,287
Transmission (right-of-way land use) (g)							(ha/km of line)	
115-kV							2.67	
230 - 287-kV							3.43	
345-kV							3.93	
500-kV							4.42	

(a) Generation impact data taken from "Resource Programs Final EIS: Volume 1: Environmental Analysis," except as noted.

(b) Includes impacts from generation only. Highest impact estimates used when range given.

(c) Sulfur emitted as Hydrogen Sulfide.

(d) Air emissions average of predicted emissions from Tenaska II, Coyote Springs, U.S. Generating Hermiston.

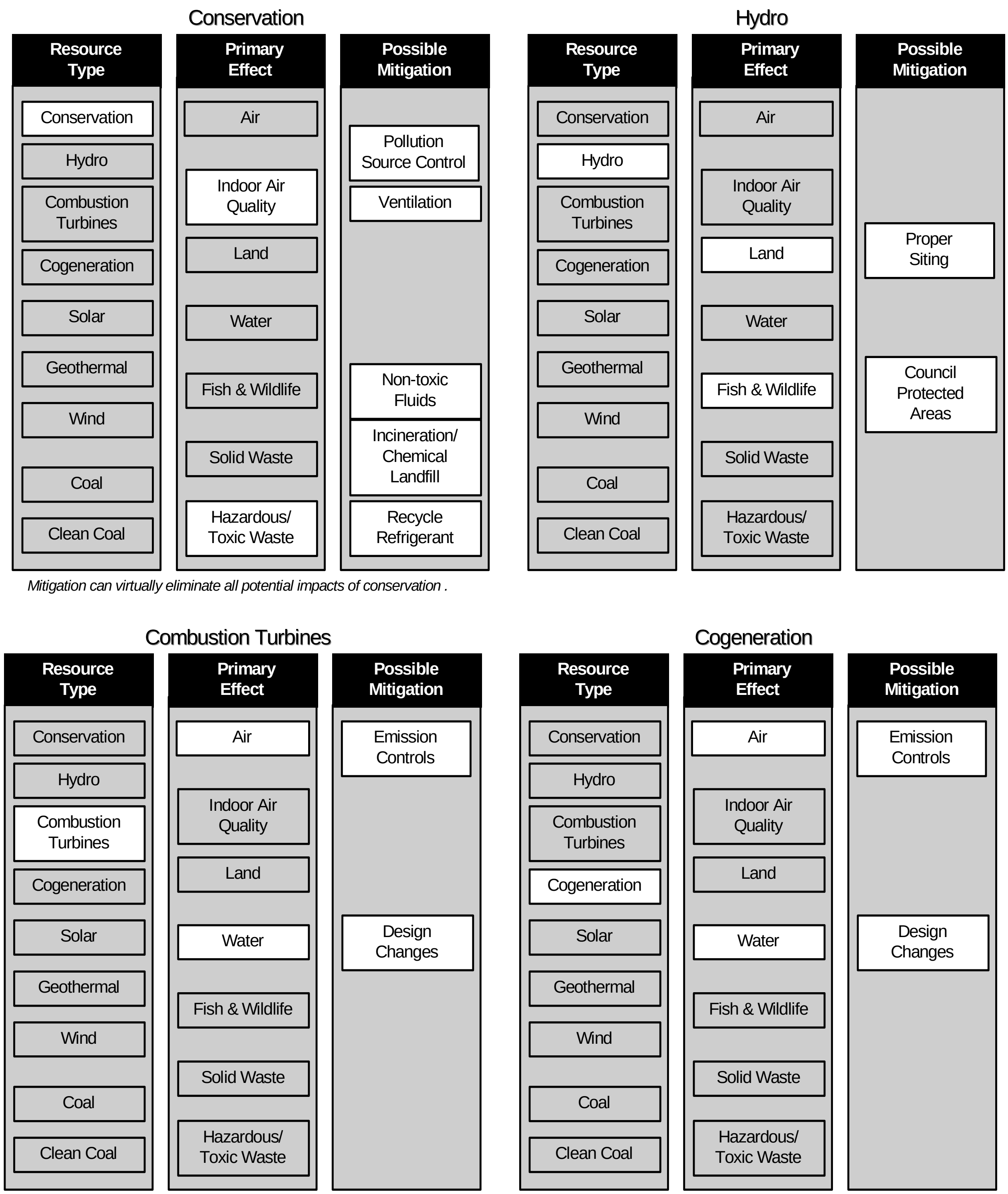
(e) Average of emissions rates for gas water heaters and gas furnaces.

(f) Assumed all combustion turbines.

(g) Based on average ROW width for BPA transmission lines in new corridors.

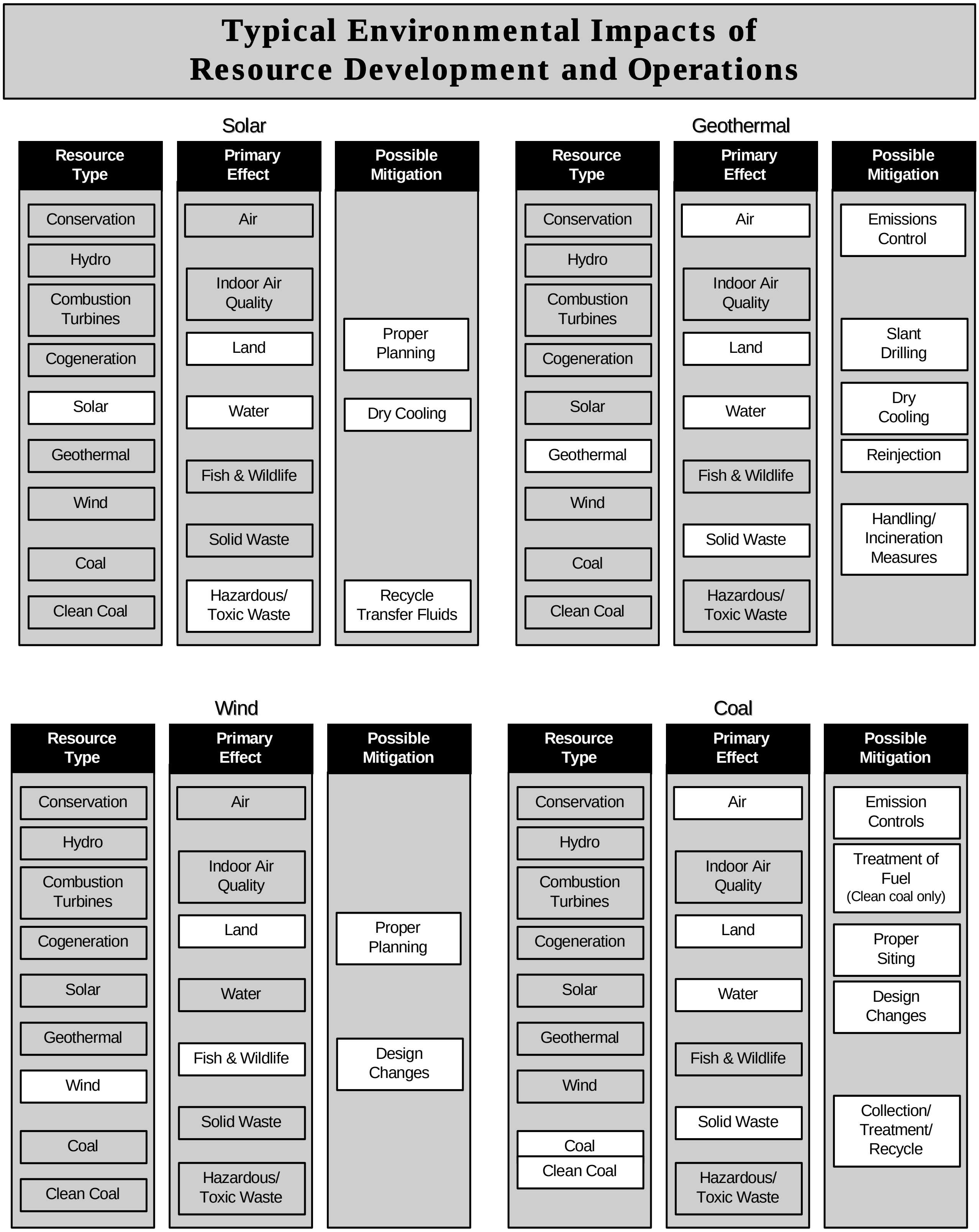
FIGURE 4.3-1

Typical Environmental Impacts of Resource Development and Operations



These charts are from BPA's Resource Programs Final Environmental Impact Statement (DOE/EIS-0162, February 1993).

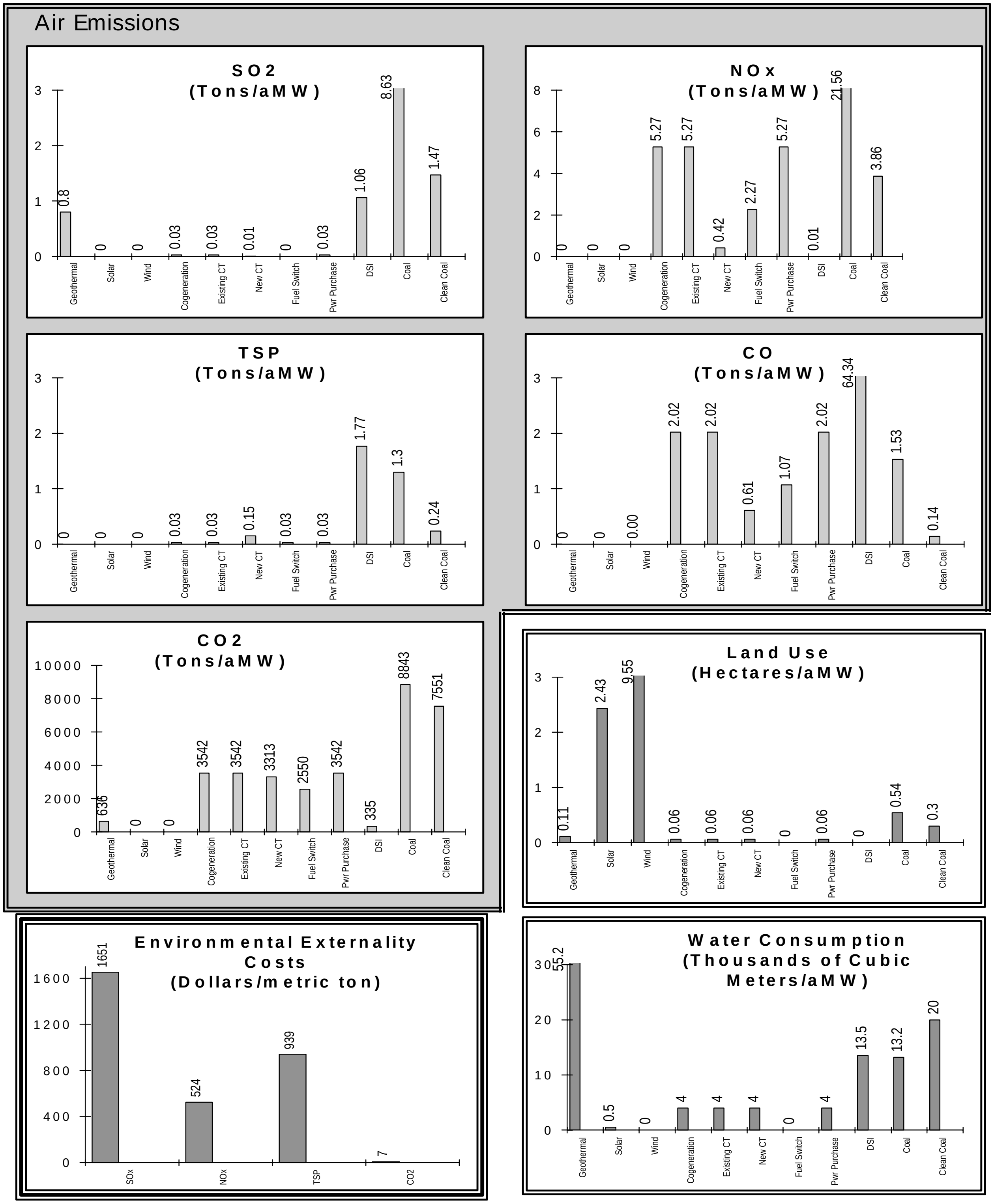
FIGURE 4.3-1 (continued)



These charts are from BPA's Resource Programs Final Environmental Impact Statement (DOE/EIS-0162, February 1993).

FIGURE 4.3-2

Level of Key Environmental Impacts By Resource Type Per aMW *



* Conservation was not included on the charts because it does not affect any of the key air, land, or water concerns.

Under development are improved combustor and blade designs allowing higher firing temperatures; and innovative recuperative cycles including intercooled, humid air, and chemically recuperated designs. Chemically recuperated designs can achieve thermal efficiencies in excess of 50 percent, compared to the 46- to 47-percent efficiencies typical of current CTs. Environmental control research focuses on combustion control of NO_x to reduce or eliminate the need for catalytic controls on the turbine exhaust. Combustion turbine research and development is expected to lead to smaller, more efficient, less costly, and environmentally cleaner generating plants (Northwest Power Planning Council, February 1994).

Because emission rates vary considerably between older CTs and newer technologies, and because CT technology is evolving so quickly, the emission rates in table 4.3-1 include separate air emission rates for existing and new CTs. Rates for existing CTs are taken from the Resource Programs Final EIS; emissions rates for new CTs are an average of predicted rates for three new existing or proposed PNW gas-fired plants with start-up dates ranging from 1991 through 1996.[3]

Fuel Switching occurs when end-use consumers change from electricity to another fuel. In the PNW, consumers most often switch from electricity to natural gas for home heating and water heating. Fuel switching has minor environmental impacts, primarily associated with the tiny amounts of NO_x and CO that can be emitted by gas water heaters and furnaces; however, these air emissions are accompanied by a reduction in environmental impacts associated with electrical generation, such as the air emissions from CTs.

Imports are electricity purchases or exchanges with other regions. A typical transaction between the PNW and California would involve a delivery of energy to California during that region's daytime summer peak loads. The energy would be returned at night to the PNW, and an additional payment in the form of energy would be delivered to the PNW during the PNW winter peak load season. The net environmental impact varies considerably according to the transaction; in this example, the delivery of energy from the PNW to California would be supported by increased hydroelectric generation to support fish migration flows (with a positive impact), and, in California, thermal generation and its air quality impacts would be moved from on-peak periods (when air quality concerns are greatest) to off-peak periods. Other imports could involve the purchase of energy during off-peak periods in other regions—for example, the purchase of energy from thermal resources in California or the ISW during nighttime or winter periods. Environmental impacts would be primarily the air emissions associated with thermal generation.

Natural gas serves a key role in the U.S. Administration’s *Climate Change Action Plan*, with Administration strategies seeking to increase natural gas share of energy use as a means of reducing greenhouse gas emissions through substitution for other fossil fuels (Energy Information Administration, 1994). Nonetheless, natural gas does create its own environmental impacts in production. Although pipeline capacity exists to ship U.S.-produced gas supplies to supply cogeneration plants, most of the natural gas expected to supply those plants, CTs, or fuel switching would be produced in the western provinces of Canada (British Columbia and Alberta).

Development of gas wells and production facilities involves exploration, drilling, production, processing, transportation, and finally, decommissioning of facilities and site reclamation. Many of the associated facilities are linear: seismic lines, roads, pipeline rights-of-way, and power lines. Construction and use of these facilities can lead to increased habitat fragmentation and reduced habitat effectiveness for a variety of species; reduced ecosystem integrity resulting in reduced populations and increased risk of species extinction; water source contamination; degradation of the regional airshed; and potential increases in global warming from methane and carbon dioxide. See below (4.3.1.1 and 4.3.1.2) for additional information.

4.3.1.1 Health/Environmental Effects of Air Pollutants

Particulate Matter can discolor paint, corrode metal, and reduce visibility. Animal and plant health effects depend upon the size of the particulates and the pollutants contained in the particle. Particulate matter less than 10 microns in diameter travels deep into the lungs, where pollutants can rapidly diffuse into capillary beds. Elevated particulate concentrations are associated with an increase in the severity and frequency of

[3] The plants are Coyote Springs, U.S. Generating Co. [Hermiston], and Tenaska II.

respiratory diseases. The EPA is currently considering lowering the primary PM-10 (particulate matter of 10 microns or less) standard because the existing standard (75 $\mu g/m^3$) does not adequately protect human health.

Carbon Monoxide can affect animals at low concentrations, although ambient concentrations do not measurably affect plants or materials. CO has 210 times more affinity for red blood cells than does oxygen, so continued exposure to CO interferes with the oxygen-carrying capacity of the blood. Prolonged exposure to low levels can impair physical coordination and cause dizziness. Continued exposure to CO above 750 parts per million (ppm) can cause death.

Sulfur dioxide negatively affects visibility. When combined with moisture, it forms sulfuric acid, which corrodes most building materials and causes lake acidification and loss of plant life. Sulfuric acid and SO_2 are both respiratory irritants. About 40 percent of the natural gas processed in the province of Alberta (Canada) contains sulphur and is termed "sour gas." Processing removes much of the sulphur in gas, recovering it as a salable by-product. Another by-product is sulphur dioxide, which can acidify and impoverish soils and have long-term effects on crops and forests, and possibly on nearby livestock.

Nitrogen oxide has effects similar to SO_2. NO_2 can also slow plant growth and reduce crop yield at relatively low concentrations. NO_2 is a respiratory irritant which, in the presence of sunlight, combines with hydrocarbons to form photochemical smog (ozone, peroxyacetyl nitrate (PAN), and peroxybenzoyl nitrate (PBN). Photochemical smog drastically reduces visibility and causes respiratory and eye irritation.

Ozone in the upper atmosphere protects the earth from ultraviolet radiation. Ground-level ozone, however, degrades rubber and is a respiratory and eye irritant. Ground-level ozone is created during a series of chemical reactions catalyzed by sunlight which involve NO_2 and hydrocarbons.

Carbon dioxide is a natural product of respiration. It is taken up by plants during photosynthesis; they use it as a building block for leaves and growth. Elevated concentrations are known to accelerate plant growth. Atmospheric CO_2 absorbs heat radiated from the earth, preventing heat loss to space. For this reason CO_2 is considered a greenhouse gas and has been linked to global warming. It has no health effects at atmospheric concentrations. CO_2 is also produced during the production of natural gas.

Methane, a large component of natural gas, is also released during production and transportation. Methane has a global warming potential 21 times (weight basis) greater than that of carbon dioxide (USDOE, 1991). However, emissions of carbon dioxide attributable to production and use of natural gas are lower than those for coal and oil. Emissions of methane attributable to production and use of natural gas are a portion of total global methane emissions; other sources include agriculture (rice and cattle in particular) and coal mining (USDOE, 1991).

4.3.1.2 Effects of Road and Natural Gas Pipeline Building in Canada

Some natural gas development, carried out for export, could adversely affect a variety of species, including grizzly bears, caribou, elk, songbirds, and bull trout. The building of linear facilities such as roads and pipelines could dissect and fragment blocks of wildlife habitat, reducing their effectiveness in providing shelter, forage, and security to certain species, although not all effects apply to all species. Some species may avoid the area, and mortality rates may rise. Severe fragmentation may reduce a population's ability to sustain itself.

Fragmentation and road density pose particular concerns for species such as grizzly bear. Although there is no specific Endangered Species Act in Canada, several other statutes exist to provide protection for wildlife, including the Wilderness Areas, Ecological Reserves, and Natural Areas Act, which offers the opportunity to set aside areas for protection from development. Land use restrictions offer differing degrees of protection for portions of forested and wilderness areas, and new gas wells may be explored in agricultural rather than forested areas.

Newer exploration and drilling techniques helping to mitigate ecosystem effects are being used in British Columbia and Alberta. These include substituting helicopter-deployable seismic rigs in place of truck-deployable seismic rigs, and using horizontal and directional drilling to access multiple natural gas fields

(Natural Resources Canada, 1994). Both techniques reduce the requirements for access road construction and use.

4.3.2 Transmission Development and Operation

A number of environmental impacts are typically associated with the construction and operation of transmission lines, no matter where they are located. Figure 4.3-3 summarizes these impacts. The amount or severity of the impact can vary according to line location, voltage and structure; and with each utility's design, construction, and maintenance practices. The following description of typical transmission line environmental impacts is drawn largely from the Delivery of the Canadian Entitlement EIS (DOE/EIS-0197, February 1994).

4.3.2.1 Land Use

The amount of new and existing rights-of-way used directly affects land use. Building a transmission line where none has existed before could have a major impact on residential, commercial, agricultural, and forest land because new line segments and access roads would intrude on existing land use or eliminate some uses altogether. A transmission project that proposes to widen existing right-of-way or rebuild a line within the same width creates fewer impacts on most, though not all, land uses. Where visual quality has already been affected by existing transmission lines, for example, adding another may not change conditions significantly. (However, upgrading from lower to higher voltage may increase visual impacts in some areas because higher-voltage lines generally require taller towers.) An expanded right-of-way on commercial forest or farmland, on the other hand, could have a major impact because new land would be cleared or removed from production. High-voltage lines create long-term visual impacts on most land uses, although they may be more compatible with industrial areas.

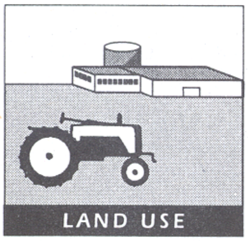
Land use impacts of transmission lines vary according to a number of factors, including voltage, insulation design, conductor, conductor tension, span lengths, structures, and conductor configuration and spacing. Typical right-of-way widths for single-circuit BPA transmission lines are shown in table 4.3-2.
Table 4.3-1 (previous section) shows average amounts of right-of-way per kilometer of line.

Table 4.3-2: Typical Right-of-Way Widths of BPA Transmission Lines

Voltage	Structure Type	Right-of-Way Width (m/ft)
115-kV	Single pole wood	21/70
	H-frame wood	24-32/80-105
230-kV	H-frame wood	35-37/115-120
	Steel	32-35/105-115
500-kV	Steel	37-52/120-170

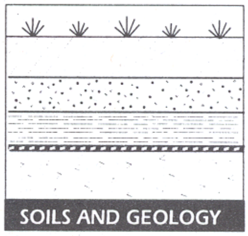
FIGURE 4.3-3

Typical Environmental Impacts of Transmission Lines



EFFECTS
- Farmland removed from production
- Forests cleared
- Aircraft hazards
- New roads

MITIGATIONS
- Location changes
- FAA marking requirements

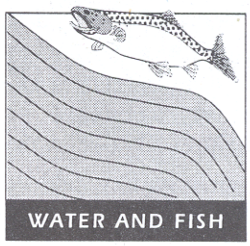


EFFECTS
- Erosion/soil movement from construction
- Stream sedimentation during/ after construction
- Reduced line reliability from snow/ ice /avalanches

MITIGATIONS
- Revegetation
- Road design
- Location changes

EFFECTS
- Vegetation/habitat destruction
- Soil compaction

MITIGATIONS
- Span small wetlands
- Mats or tracked construction equipment
- Off-site compensation

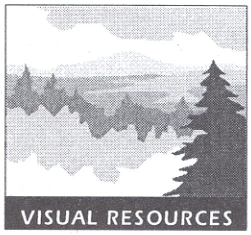


EFFECTS
- Reduced aquatic life survival from sedimentation
- Reduced habitat quality from herbicide use

MITIGATIONS
- Tower sites away from streambanks
- Span small streams
- Revegetation
- Silt fences

EFFECTS
- Vegetation/habitat changes
- Increased hunter access
- Wildlife disturbance during breeding, calving, critical seasons
- Bird collisions with conductors

MITIGATIONS
- Revegtation with low-growing species
- Construction timing
- Mark conductors with balls, etc.

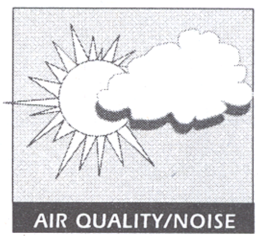


EFFECTS
- Structures incompatible with recreation, residential, scenic areas

MITIGATIONS
- Special tower designs
- Darkened towers in forests
- Non-shiny conductor
- Location changes

EFFECTS
- Disturbance of subsurface sites
- Visual intrusion on historic buildings/ districts or religious sites

MITIGATIONS
- Pre-construction surveys
- Salvage or physical protection
- Location changes



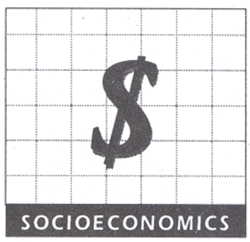
EFFECTS
- Fugitive dust
- Vehicle emissions
- Construction noise

} temporary, during construction

MITIGATIONS
- Federal, state, and local air quality and noise regulations

EFFECTS
- Electric shocks
- Conductor noise
- Electrical interference with electronic equipment
- Potential uncertain long-term health effects

MITIGATIONS
- Safety instruction to property owners
- Ground objects near lines
- Location/design changes
- Limit use of ROW



EFFECTS
- $280,000 – $688,000 per kilometer
- Temporary population increase in rural areas
- Increased access to private lands
- Strong objections to line's presence

Agricultural land would be permanently removed from production where towers are placed in cultivated fields; however, most access roads in farmland, other than existing roads, are used only during construction, after which the land is restored to its original use. Although structures could interfere with farming operations, often they can be located or designed to reduce impacts. Transmission lines most significantly affect irrigated farmland and cropland with perennial crops such as vineyards or orchards. It is difficult for farmers to cultivate around tower sites in the middle of fields and difficult and expensive to adjust irrigation equipment to tower sites. Loss of orchard land or vineyards to tower sites represents loss of a long-term investment, in addition to loss of annual income from the crops. (It is BPA's policy to compensate for such impacts.)

Commercial forest land (except Christmas tree farms or nurseries) would be removed from production for any new or expanded right-of-way and access roads, because only low-growing trees and shrubs are allowed on the right-of-way.

Effects on recreational land use are primarily visual (see Visual Resources).

Transmission lines near airports create significant hazards for aircraft. Normally, such locations are avoided. However, if a line must be located near an airport, towers are marked to Federal Aviation Administration (FAA) specifications to make them clearly visible to pilots. These markings may be an unwelcome visual impact on other users.

4.3.2.2 Soils and Geology

If construction occurs in areas with steep slopes and moderate soil erosion potential, soil may erode. This is true for construction in new, expanded, or existing corridors, although the greatest potential for impact would be in a new corridor because new right-of-way generally requires new access roads. If erosion is severe, vegetation recovery may be slow, and slumping (mass movements of soil down slope) and sedimentation of nearby streams may occur. Because line maintenance requires using access roads, soil impacts may continue over a long period.

Areas of severe weather conditions can create problems in maintaining a transmission line's reliability. Heavy snow or ice loads and avalanches can cause a line to fail by toppling towers or causing conductors to sag to the ground. While engineers can design towers to withstand such forces, such structures increase a line's cost. If possible, lines are sited to avoid such conditions.

4.3.2.3 Floodplains and Wetlands

Construction of structures and access roads may adversely alter wetlands and destroy vegetation and fish and wildlife habitat unless special construction practices are used. Long-term impacts are caused when heavy construction equipment compacts the soil, which changes the drainage patterns and sometimes vegetation types. Often, however, transmission lines can span or avoid smaller wetlands altogether, thus avoiding impacts entirely. If structures must be placed in a wetland, contractors use special tracked machines or mats to minimize impacts. If impacts still occur, section 404 of the Clean Water Act requires on-site or off-site mitigation or compensation.

4.3.2.4 Water and Fish

Clearing new right-of-way, expanding existing right-of-way, and constructing access roads can increase sediments in streams. The extent of the effect depends on the proximity of construction activity to a stream. Accumulation of sediment may change pool shape and size and may affect water quality. This in turn adversely affects aquatic life such as anadromous and resident fish. Use of herbicides to clear vegetation may also affect fish by removing vegetation that shades the water and keeps it cool. BPA meets state and Federal regulations for buffers beside streams and, if herbicides are used in these areas, they are sprayed by hand.

If sediment and turbidity are increased, then aquatic plant productivity is decreased. In turn, aquatic insect food sources are reduced. These impacts move up the food chain, eventually reducing fish numbers. The increased sediments hinder the emergence of alevins (baby fish) from their eggs in stream gravels and decrease winter survival by filling in channel pore spaces and reducing the channel's potential to produce food.

In most cases, proper erosion control practices result in only short-term sedimentation increases. For example, to protect its structures, BPA does not normally place them close to stream banks because erosion could undermine them, and does not allow construction equipment in streams. In steep areas, small streams usually are spanned. Revegetation to stabilize the soil and use of fabric fences to hold back silt also prevent sedimentation.

Transmission line options that use existing corridors would have the lowest impacts on water quality and fish because the right-of-way already would be cleared and most access roads would be in place.

4.3.2.5 Vegetation and Wildlife

Clearing new and expanding existing rights-of-way can create major impacts on vegetation. Existing vegetation is removed, and vegetation composition may change, most notably in forested areas where all tall-growing vegetation must be removed. Maintenance practices, including herbicide use and danger-tree cutting, ensure that only low-growing vegetation survives over the long term. Although disturbed areas can be reseeded with low-growing plants, success rates vary. If a line uses existing right-of-way, little or no additional clearing of existing vegetation is needed.

Right-of-way clearing for new corridors changes the habitat for wildlife and increases access for hunters. Expanding existing right-of-way would disturb wildlife or cause them to leave the area during construction. This impact can be especially severe during breeding, calving, or other critical seasons. Right-of-way expansion would change some habitat permanently. Using existing right-of-way would disturb wildlife during construction only.

4.3.2.6 Visual Resources

In areas used for recreation, particularly in undeveloped places, studies show that many users find transmission lines to be an unwelcome visual intrusion. Also, many citizens feel strongly that transmission lines near their homes are visually intrusive, and that some property values may be reduced. Adverse visual effects may be perceived up to several kilometers from the line. Transmission lines may be more compatible with industrial areas. The effectiveness of potential mitigation measures depends on the site, and some measures may substantially increase the cost of the project. Possible measures include darkened towers in forested areas; different tower designs more compatible with a particular environment; non-specular (non-shiny) conductor; and locations that avoid visually sensitive areas.

4.3.2.7 Cultural Resources

Construction may disturb subsurface resources such as archeological sites and may intrude visually on historic buildings or districts. With careful preconstruction surveys and consultation with Native American and historical properties experts, impacts on most subsurface sites can be avoided or mitigated.

4.3.2.8 Air Quality and Noise

Construction of transmission lines has the potential to affect air quality of an area, particularly during dry periods in late summer, by disturbing the soil and raising fugitive dust. Standard construction practices keep such occurrences at a minimum. Construction contractors are required to comply with all Federal, state, and local air quality standards, including vehicle emissions standards.

Contractors must also comply with all noise regulations by observing maximum decibel levels for machinery and ceasing construction activity during certain hours to avoid disturbance to nearby residents.

4.3.2.9 Health and Safety

BPA recognizes strong public concern regarding the possible effects of the electrical properties of transmission lines on public health and safety. These effects include electric shocks, noise, and the potential long-term health effects of EMF.

Safety. All BPA lines are designed and constructed in accordance with the National Electrical Safety Code (NESC), which specifies the minimum allowable distances between the lines and the ground or other objects to minimize hazards from electric shocks. Grounding of certain objects near the line is standard construction practice to reduce the potential for shocks that may be induced by a line near objects such as wire fencing on wood posts. For more information, see the BPA publication, Living and Working Around High-Voltage Power Lines (DOE/BP-1821).

Corona Effects. Transmission lines produce corona, the molecular breakdown of air very near conductors that occurs when the electric field is greatly intensified at projections (such as water droplets) on the conductor. Although BPA lines are designed to meet all state and Federal audible noise standards, corona may cause noise and electrical interference to nearby homes or businesses. All problems are investigated and, if the BPA facility is involved, most effects can be mitigated by minor modifications to the lines or to the affected equipment. Studies have shown that the minute amount of ozone produced by corona generally is not detectable above average background levels.

Electric and Magnetic Fields (EMF). Both electric and magnetic alternating-current (AC) fields induce currents in conducting objects, including people and animals. These currents, even from the largest power lines, are too weak to be felt. However, some scientists believe that the currents may be harmful and that long-term exposure should be minimized.

Hundreds of studies on electric and magnetic fields have been conducted in the United States and other countries. Studies of laboratory animals generally show that these fields have no obvious harmful effects. However, a number of subtle effects of unknown biological significance have been reported in some laboratory studies (Frey, 1993).

Much attention at present is focused on several recent reports suggesting that workers in certain electrical occupations and people living close to power lines have an increased risk of leukemia and other cancers (Sagan, 1991; NRPB, 1992; ORAU Panel, 1992; Stone, 1992). Most scientific reviews, however, find that the overall evidence is too weak to establish a cause-and-effect relationship between electric or magnetic fields and cancer. For this reason, BPA is unable to predict specific health risks related to exposure to EMF.

There are no national standards for EMF. Six states, including Oregon and Montana, have electric field standards, but no PNW state has yet established a magnetic field standard. BPA has an electric field standard of 9 kilovolts per meter (kV/m) maximum on the right-of-way and 5 kV/m at the edge of the right-of-way. However, because of the scientific uncertainty and in response to public concern, BPA has taken additional steps. These include: developing Guidelines on EMF that name EMF as a major decision factor to be considered in locating and designing new BPA facilities; discouraging intensive uses of rights-of-way that would increase human exposure to EMF; and not increasing public and employee exposure to EMF where practical alternatives exist. A task force is currently reviewing guidelines.

More detailed information on effects of EMF or corona can be found in a BPA publication, Electrical and Biological Effects of Transmission Lines: A Review (DOE/BP-945).

4.3.2.10 Socioeconomic Effects

Typical construction costs for transmission lines range from $280,000/km ($450,000/mi) of 230-kV double-circuit line to $690,000/km ($1.1 million/mi) of double-circuit 500-kV line. How these costs are translated into the rates BPA charges its customers for transmission services depends on BPA's total costs and is decided in BPA's rate case process.

Construction crews for major lines would noticeably increase the population of some rural areas, a temporary effect. New access roads may increase access to private land, and individuals living near a transmission line may strongly object to the line's presence.

4.3.2.11 Differences in Transmission Lines Among Utilities

There are differences in the design, construction, and maintenance of transmission lines between BPA and other utilities; however, it is difficult to identify consistent differences between BPA transmission lines and other utilities' as a class. Differences can be attributed to such factors as clearance policy (BPA designs to NESC standards plus buffers, whereas other utilities may use other buffers), design criteria (not all designs at a given voltage have the same phase separation, structure types, or conductor designs, for example), design parameters (such as switching surge), and maintenance requirements. BPA typically avoids use of herbicides to maintain vegetation in transmission line right-of-ways; other utilities may use herbicides more frequently. BPA's transmission lines are all on separate right-of-ways; many other utilities have pole easements only for lower-voltage transmission lines.

4.3.2.12 Lower- Versus Higher-Voltage Lines

Higher-voltage lines are more efficient than lower-voltage lines in transferring power. For a given amount of power transfer, as the voltage level increases, the current level decreases. Because resistive losses increase as a function of the square of the current load, for a given amount of power transfer and a given conductor, higher-voltage lines have fewer resistive losses. More efficient transmission of power through the use of higher-voltage lines can lead to lower environmental impacts for two reasons.

First, the same amount of power can be transferred with fewer kilometers of high-voltage lines than with lower-voltage lines, so although higher-voltage lines require wider right-of-ways and have more massive structures, fewer lines have to be constructed. Higher-voltage lines can move more power from source to load for less cost per megawatt, less land-use per megawatt, and less raw material use overall per megawatt.

Second, more efficient transmission on higher-voltage lines means that less generation is required to serve the same amount of load. More efficient transmission lines can therefore be equated with energy conservation.

4.3.3 Consumer Behavior

Changes in BPA products, services and rates directly affect its customers—public and investor-owned utilities and DSIs. To the extent that utilities pass those changes through to their retail consumers, they can affect end-use consumers or change consumer behavior. The following sections describe typical impacts of changes in utility products, services and rates on each major retail consumer sector. They also address general impacts on DSIs. Figure 4.3-4 summarizes these effects.

4.3.3.1 Residential Sector

In the retail residential sector, the primary environmental impacts of changes in BPA's products, services, and rates would occur from residential conservation and fuel switching. Household incomes could also be affected by changes in home heating and lighting costs. In general, environmental impacts associated with both residential conservation and fuel switching are minimal. The following discussion of environmental impacts is summarized from the Resource Programs Final EIS (DOE/EIS-0162, February 1993).

Conservation

House-tightening measures may increase levels of radon gas within weatherized houses. Radon gas is a naturally occurring gas associated with increased rates of cancer in humans. Measures to reduce the build-up of radon within weatherized houses are now standard for BPA and other regional residential conservation programs, so no significant health impacts from radon are expected from those programs.

Fuel Switching

Fuel switching occurs when retail electricity users switch to some other energy source for some uses. Most typically, fuel switching in the residential sector involves changing from electricity to natural gas for space-and water-heating. Fuel switching can lead to minor environmental impacts in two areas: air quality and land and soil impacts of fuel line installation.

Air quality impacts of fuel switching result from the combustion of natural gas in the home for water- and space-heating. Although natural gas is a fairly clean fuel, burning natural gas in the home does produce small emissions of NO_x, CO, and CO_2 (see table 4.3-1). It should be noted that, overall, direct use of natural gas for water- and space-heating converts fuel to useful energy more efficiently than burning fuel to operate a CT to generate electricity for the same use. Overall, fuel-switching may produce fewer air emissions than generating electricity for the same end use; however, the emissions associated with fuel switching typically occur in populated areas with a greater potential for air quality problems, whereas (at least in the PNW) in many cases CTs are located outside major population areas.

The installation of gas distribution lines can create temporary impacts on soils during construction. Soils can be compacted, and construction site runoff must be managed to reduce the potential that might reach storm drains or streams. Overall, the environmental impacts of installing gas distribution lines are fairly minor, and typically regulated by state and local building and environmental protection codes.

Socioeconomic Impacts

If residential end users cannot conserve electricity to reduce the cost impacts of changes in BPA products, services, and rates, their costs for home heating and lighting could increase. The extent to which such increases would affect household net incomes would depend on many factors, including the degree to which retail utilities passed through changes, the amount of electricity consumed, options for changing consumption patterns (e.g., using programmed thermostats or shutting off more lights), and the share of electricity costs in total household budgets. In general, it is likely that any rate impact passed through by retail utilities would have a minor effect on most household incomes, but would have proportionately more impact on lower-income households. Where planners intend that some conservation potential be achieved through price signals, adoption of conservation measures in response to price would occur more frequently among higher-income consumers, and consumers unable to finance conservation measures would spend a larger portion of their income on electric energy. Some consumers might change their electricity use patterns if electricity cost more during peak-use times of the day or during certain seasons when power is less available.

4.3.3.2 Commercial Sector

In the commercial end-use sector, the environmental impacts associated with changes in BPA's products, services, and rates would be in three areas: commercial sector conservation, fuel switching, and the socioeconomic impacts associated with changes in costs or loads.

Conservation

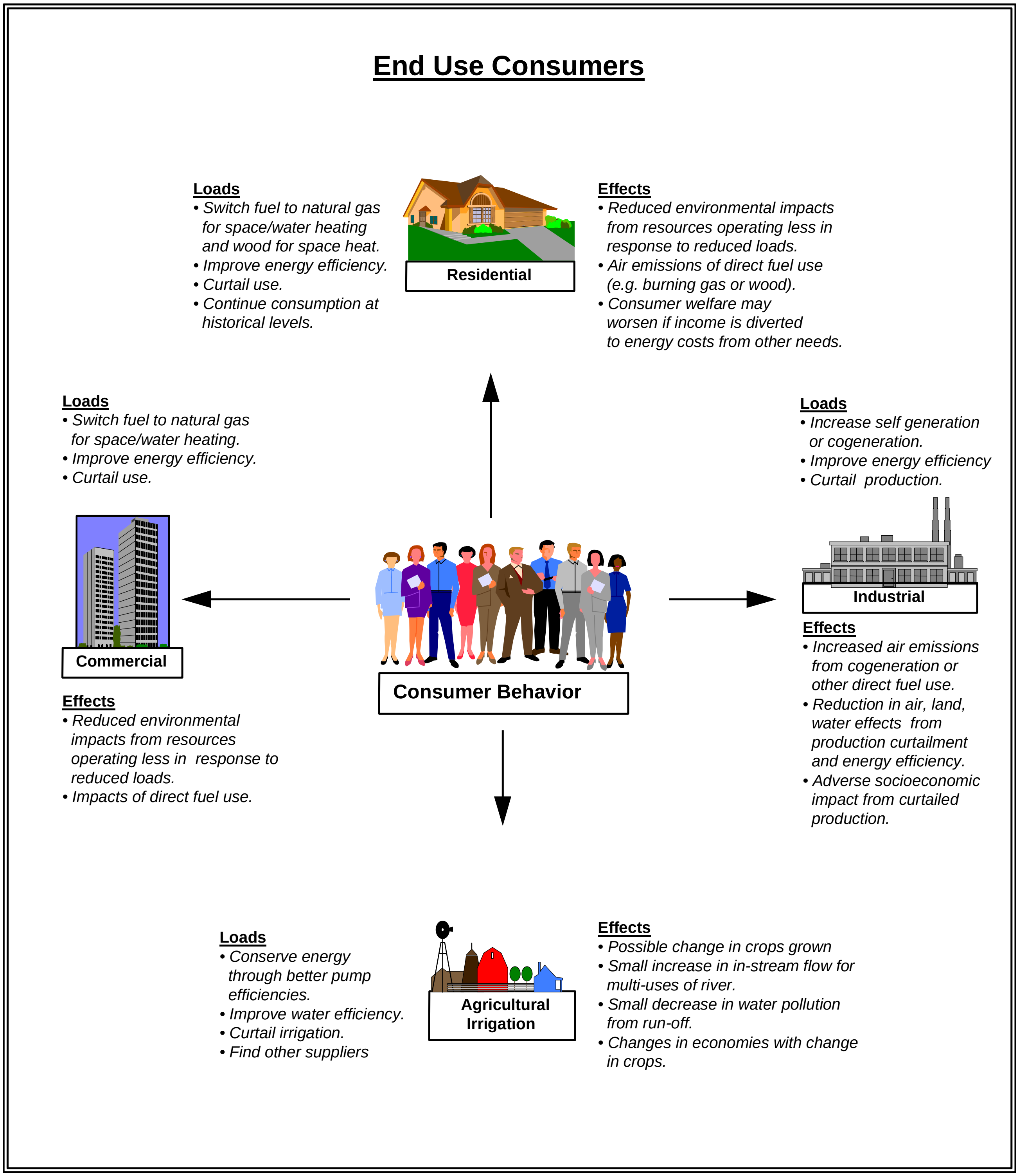
The Resource Programs Final EIS (DOE/EIS-0162, February 1993) identifies potential environmental impacts associated with commercial sector conservation programs. In general, conservation would have positive environmental impacts overall by reducing new generating resource development; the only potential negative impacts (e.g., indoor air quality and the use of hazardous or polluting materials or technologies for energy efficiency) are generally effectively mitigated.

Fuel Switching

Some commercial end users may switch to natural gas for heating loads. Fuel switching could have minor air quality impacts from combustion. There might also be minor environmental impacts associated with gas delivery (e.g., excavation for distribution pipelines), but these types of in-ground impacts are typically regulated locally and typically have minimal net long-term environmental impacts.

FIGURE 4.3-4

CONSUMER BEHAVIOR
LOADS AND EFFECTS FROM INCREASED RETAIL RATES



Socioeconomic Impacts

Changes in BPA products, services, and rates, to the extent passed through by retail utilities to end-use consumers, could affect the energy costs experienced by commercial businesses. For marginally profitable businesses, increased energy costs could be enough to cause these firms to fail, reducing employment and local incomes. However, the potential for this type of impact to have any significance on a regional or commercial-sector scale is small, and impacts on individual businesses would depend on the businesses' energy costs, total operating costs, opportunities to reduce electricity consumption, and market prices for their products and services.

4.3.3.3 Industrial Sector

The primary impact of changes in BPA's products, services, and rates passed through to the industrial sector would be associated with fuel switching, self-generation and cogeneration, industrial sector conservation programs, and socioeconomic impacts (e.g., employment and income changes).

Fuel Switching

Switching from electricity to natural gas or other fuels is an option in some PNW industries. The most likely fuel choice in many areas would be natural gas, although some wood products firms may be able to use wood waste. The environmental impacts would vary according to the fuel used and the industrial process; in general, fuel switching to natural gas would have minor air quality impacts.

Self-Generation and Cogeneration

Some large industrial firms could replace electricity purchases from their local retail utility by developing their own generation (on-site generation to substitute in part for purchased electric power) or cogeneration (on-site cogeneration facilities to produce heat and steam for industrial uses and to generate electricity for plant use and/or for sale to utilities). The most likely technology would be natural gas-fired cogeneration or CTs. The typical environmental impacts of CTs and cogeneration are described in section 4.3.1. Cogeneration projects at many large industrial sites (particularly in the pulp and paper industry) often replace wood-waste or diesel-fired boilers with gas-fired boilers, leading to a net improvement in air quality at the site.

Conservation

Industrial conservation measures vary considerably by industry, but generally include the following types of measures:

- High-efficiency motors
- Adjustable/variable speed drives
- Energy-efficient motor rewinds
- Heat recovery equipment
- Thermal storage
- Insulation
- Process heat equipment
- Compressed air systems
- Lighting efficiencies
- Energy management improvements
- Materials handling improvements

- Power factor improvements
- Cooling tower conservation
- Pump and fan efficiencies
- Distribution transformer improvements
- Dehumidifiers
- Furnace upgrades
- Water recycling processes
- Refrigeration system improvements.

Most of the measures listed above do not alter existing mechanical processes in ways that lead to increases in waste streams or adverse environmental impacts; in fact, many industrial sector conservation programs simultaneously reduce electricity use and waste streams. In most industrial applications, there is sufficient environmental regulation to address any potential adverse impacts that result from process modifications to reduce energy use. In most cases, energy conservation would have positive impacts by reducing the need for new generation and increasing the efficiency of the industrial process, thereby reducing other waste streams.

Socioeconomic Impacts

If rate changes were passed through to the industrial customer, and if that customer could not reduce electricity costs by conservation, fuel-switching, or process changes, some marginal firms could experience changes in overall production costs that could threaten their economic viability. Specific impacts are difficult to predict, but industries primarily affected would be marginally viable ones for which electricity costs are a large share of total production costs and which have limited ability to shift to other fuels or to reduce consumption.

4.3.3.4 Agricultural Sector

The environmental impacts associated with rate design changes passed through to irrigation sector end users would include impacts from irrigation sector conservation, socioeconomic impacts on the agricultural sector, and, potentially, land use changes from shifts in cropping patterns.

Conservation

The Resource Programs Final EIS (DOE/EIS-0162, February 1993) addresses potential environmental impacts associated with irrigation sector conservation programs. The EIS notes that the environmental impacts associated with most of the energy conservation measures result in a new positive environmental impact, because both energy and water consumption are reduced and equipment life is extended. The EIS goes on to explain that the few potential negative environmental impacts of irrigation conservation measures, largely due to the potential for increased soil erosion from some sprinkler irrigation methods, are mitigable.

Socioeconomic and Land Use Impacts

If changes in electricity products, services, and costs are passed through to the farmer, total farm operating costs could change. If energy costs increase, some marginal operations could become uneconomical. The most vulnerable operations would probably be high-head pumping operations, primarily in arid areas of the PNW with mostly sandy soils, and crops for which pumping is a larger share of total costs (e.g., wheat). For many of these vulnerable operations, grazing is probably the chief alternative use of the land.

In other cases, increased irrigation costs could cause farmers to change cropping patterns to crops that use less irrigation water in order for their operations to remain viable.

4.3.3.5 Direct Service Industries (DSIs)

The Direct Services Industry Options Final EIS (DOE/EIS-0123F, 1986) addressed the environmental and socioeconomic impacts of all the Northwest primary aluminum smelters, all of which are DSIs. While some conditions have changed, the EIS continues to be a substantially accurate assessment of the environmental and socioeconomic impacts of the smelters. The Reynolds Troutdale smelter, an old prebake plant, is currently closed. All PNW smelters re expected to continue operating at full capacity for the near future due to low prices for power.

Past practices of smelters caused some environmental problems when environmental regulations were less stringent and the effects of smelter air and water pollutant discharges and solid wastes were less well understood. Aluminum smelters are major sources of a number of important air pollutants, including CO, SO_2, particulate matter, and CO_2. They also emit several hazardous air pollutants (HAP) and greenhouse gases. Current practices and regulations reduce smelter discharges, so now operations generally do not cause appreciable harm (Direct Services Industry Options Final EIS, Appendix A).

The greenhouse gases associated with aluminum smelter emissions are CO_2, carbon tetrafluoride (CF_4), and carbon hexafluoride (C_2F_6). Typical CO_2 emissions from aluminum smelters (expressed in terms of emissions per aMW of load placed on BPA) are presented in table 4.3-1; impacts of DSI operations in each of the alternatives are shown in table 4.4-19, under section 4.4.3.8. The global warming potential of carbon tetrafluoride is approximately 5,000 times that of CO_2, and that of carbon hexafluoride approximately 10,000 times more potent than CO_2, due to the long atmospheric lifetimes associated with these compounds. CF_4 remains in the atmosphere for decades and C_2F_6 remains in the atmosphere for hundreds of years. The quantity of CF_4 and C_2F_6 emissions from aluminum smelters depends upon computer technology; the more precisely aluminum smelters can control the amount of electricity supplied to the aluminum pots, the less CF_4 and C_2F_6 will be emitted. Smelters using computer-controlled potlines emit a fraction of what older smelters emit. Typical CF_4 emissions range from 0.2 to 1 kilogram (kg) (0.44 to 2.2 pounds (lb)) per metric ton of aluminum produced and C_2F_6 emissions range from 0.04 to 0.16 kg (0.08 to 0.35 lb) per metric ton of aluminum produced.

One-hundred eighty-nine HAPs are now regulated under the Clean Air Act as revised in 1990. Aluminum smelters emit significant quantities of hydrogen fluoride, a respiratory irritant, which is one of these HAPs. Aluminum smelter hydrogen fluoride emissions range from 0.1 to 1.2 kg (0.2 to 2.6 lb) per metric ton of aluminum produced. Aluminum smelters also emit significant quantities of carcinogenic polycyclic aromatic hydrocarbons (PAH), which are also regulated HAPs. The quantity of PAH emitted depends upon each smelter's potline technology. PAH emissions range from 0.25 to 3 kg (0.55 to 6.6 lb) PAH per metric ton of aluminum produced. The EPA is in the process of setting aluminum industry emission control requirements for both PAH and hydrogen fluoride.

The recent decline in wholesale prices for electricity has benefited the region’s aluminum smelters because BPA is no longer the least-cost supplier of electricity in the Northwest. Smelters that were formerly considered “at risk” of closure can now operate through most swings of the aluminum price cycle if they can purchase power at an average cost of 20 mills/kWh, as some offered power sales demonstrate. However, if load growth on the west coast reduces the electricity surplus and gas prices rise, forcing up prices on the wholesale electric market, then some of the region’s smelters could face closure as their cost of electricity rises.

4.3.4 Impacts of Potential Hydro Operation Strategies

4.3.4.1 Introduction and Background

The discussion below of hydro generation and its impacts covers operations of the river system, and is summarized directly from the Systems Operations Review Draft Environmental Impact Statement (DOE/EIS-0170), which focused on potential changes in operations of Federal Columbia River mainstem projects. Decisions made on how to operate the river are *not* within the scope of the Business Plan EIS.

(Similarly, decisions made within the Business Plan EIS do not influence the SOR process or limit its ability to make decisions.)

The BP EIS examines changes in business practices. However, the consequences of those business changes may vary, depending on which river operations strategy is selected in the SOR process. Therefore, the discussion of hydro operations strategies below is provided for the BP EIS reader.

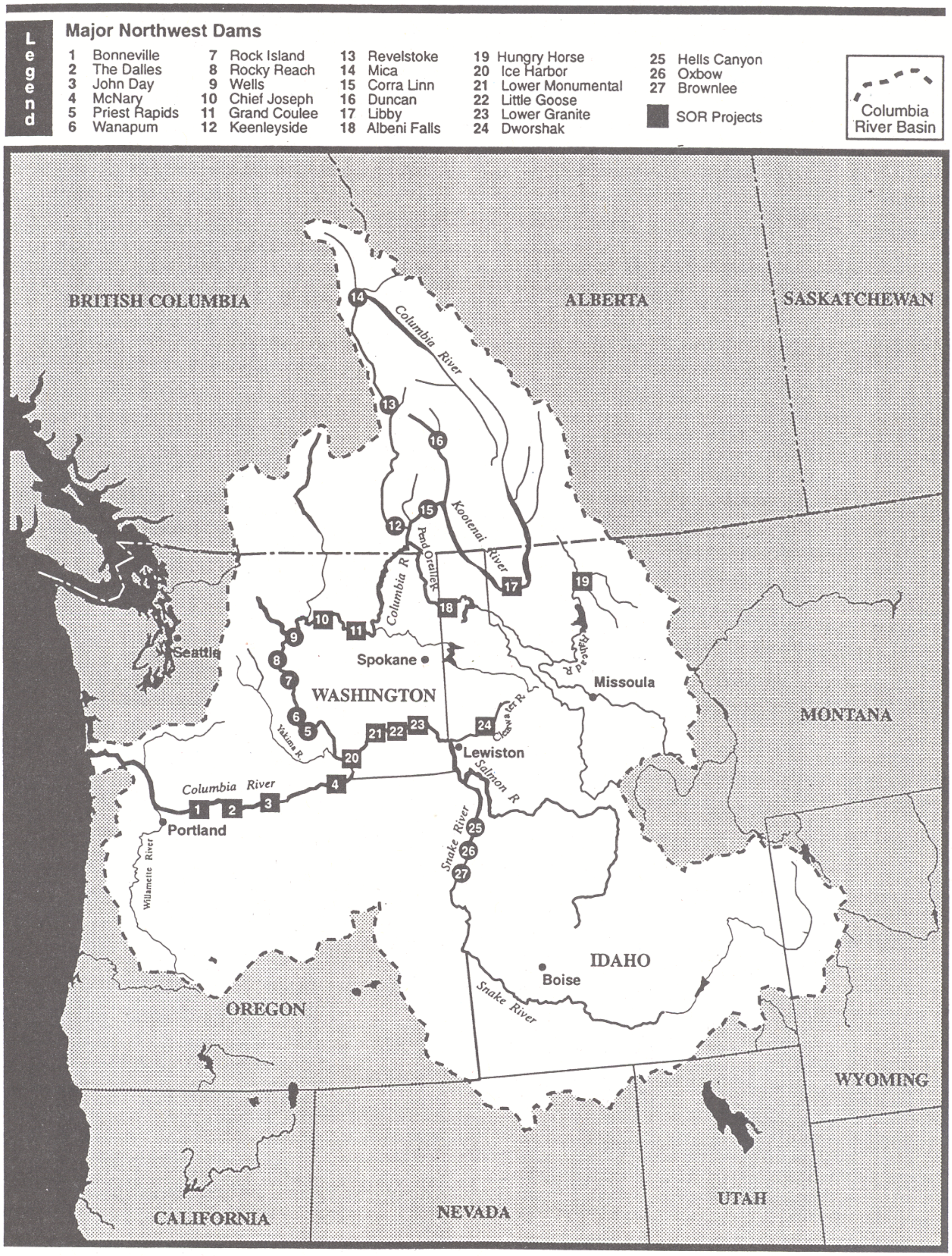
The range of river operation changes turns on the issue of how to reverse the rapid decline of anadromous salmon stocks in the river system, and particularly in the Snake River. Current river operations and the dams and turbines affect the ability of anadromous fish to migrate oceanward and return, by placing obstacles in their way and rendering them vulnerable to predators for a longer period of time before they reach the ocean, by killing fish that pass through turbines at the dams, and by increasing the difficulty of passage around dams on their return. Scientists, interested groups, agencies, and Tribes seek to address these problems, but they do not agree on the best solutions. In particular, there is disagreement in three areas: flow, spill, and in-river migration versus transportation of fish. These issues are briefly characterized below.

- **Flow.** A number of scientists believe that a key to increasing anadromous fish survival is to speed up downstream migration of juvenile anadromous fish, which is slowed by as many as nine dams. There is some disagreement as to how much an increase in flow(s) may help or how that increase may be related to travel time. However, the NMFS and the Council think that a mix of water release measures (increased water to augment flows, drawdown, and more spill) should help this situation. Consequently, the Draft SOR EIS proposed a range of strategies for operating the Federal system. These System Operating Strategies (SOSs) combine the three measures in various ways and to varying degrees.

- **Spill.** When additional water is allowed to flow over dam spillways, fish migrating downstream are attracted to the increased current and "flushed" around dams more quickly. However, when water falls from a height, the amount of nitrogen in the water increases: the water becomes supersaturated with the gas, which can have debilitating and potentially lethal effects on fish through gas bubble disease. There is disagreement on what percentage of gas saturation is acceptable. The threshold has been 110 percent; some parties believe that 120 or 125 percent (one result of greater amounts of spilled water) would not appreciably affect fish mortality but would successfully speed more fish oceanward. Another consideration is the physical location of spill: it occurs at locations different from the fish ladder entrances and exits. (For distinctions between run-of-river and storage dams, please see 4.3.4.2, below.) Fish seeking upstream passage can be attracted to the increased flow from spill, where there is no way upstream, and may consequently fail to reach their spawning grounds.

  In-river migration versus transportation. Before there were dams, anadromous fish negotiated their way first downriver, then back upriver and over rapids and falls into the far reaches of the Columbia River system. Now, anadromous fish cannot get around storage dams at all (see figure 4.3-5). To increase fish migration *downstream*, the COE has been diverting fish away from turbine intakes and into channels either for bypass around dams or for transport downstream on barges or trucks (the fish are then released back into the river). Researchers estimate that more than 70 percent of Snake River steelhead and yearling spring and summer chinook smolts, and up to 40 percent of subyearling fall chinook arriving downstream, are transported around dams. Some fish die when they are transported, through shock or injury. Some fish die when instead they continue in-river over or past dams: they may be injured or killed if they pass through turbines or through gas bubble disease (see **Spill**, above). There is disagreement over whether transport is sufficiently helpful and acceptable, or whether in-river migration only would be both a feasible and superior goal.

Figure 4.3-5: Major Northwest Dams



The text below first provides background on the impacts of a full range of hydro operations, then on impacts from two Strategies from the Draft SOR EIS. These two represent likely endpoints for a range of impacts for business practices.[4]

- "**Current Operation"** (System Operating Strategy 2c) represents "No Action" in the SOR: that is, operations would continue to develop as at present, with some flow augmentation. This alternative would represent the likely least-cost option for power production and revenues.
- **"Coordination Act Report Operation"** (SOS 7a) was intended to assist anadromous fish migration through a combination of spill, increased flow augmentation, and drawdown. Of the SOS's examined in the Draft SOR EIS, it would have the most serious impacts on power production and revenues.

4.3.4.2 General Effects of Changes in Hydroelectric Operations

The text below is summarized from the Draft SOR EIS, and discusses river operations (storage and release of water) using the existing projects on the Columbia and Snake Rivers. It does not examine impacts from building and beginning operation of a new dam because the building of such dams is not part of the scope of the SOR EIS.

Hydro generation involves the control of flowing water to produce electricity. Environmental impacts derive from the storage, release, and/or diversion of water from its natural course through the dams and turbines that produce electricity. There are two types of hydroelectric projects. Storage dams store and release (draft) large amounts of water for power production and other uses. They can shift the timing of natural runoff downstream, by holding water back for later release. Run-of-river dams have limited storage capacity, and relatively minor fluctuations in water level.

Water to produce hydro power is most available in *late spring* and *early summer* when the snowpack melts. However, the heaviest demand for power in the Pacific Northwest comes in the *winter* months, largely from winter heating loads.

Under current operations, water from spring snowmelt and runoff is stored during the spring and summer and then released later in the year to supplement flow through turbines at dams and produce power. Water is also released to meet other needs, including additional water flows (Water Budget and other flow augmentation) to assist juvenile anadromous fish in their migration to the ocean.

Storage and release of water may have effects on a wide range of resources: both resident and anadromous fish, soils, vegetation, water quality, wildlife, cultural resources, recreation, navigation, irrigation, municipal uses, flood control, and power production. The following sections provide detail on effects of changes in hydroelectric operations. Storage and release often have conflicting effects: a benefit provided by one may be a drawback under the other, and vice versa. Both benefits and drawbacks are described below.

Fourteen Federally recognized Native American Tribes, each with its own reservation, are located within the SOR study area. The existing tribal and reservation structure has been shaped by treaties between the United States government and the Tribes in the mid-1800s. The right to fish and hunt on their reservations is reserved to the Tribes; Tribes generally manage fish and wildlife resources on the reservations. Off-reservation rights also include fishing, hunting, gathering activities, and use of sacred and religious sites. Anadromous fish were, and still are, central to the subsistence, culture, and religion of most Columbia Basin Tribes. Courts have reaffirmed the treaty rights of Indians to share equitably in the harvest of anadromous fish, and to continue to fish in their "usual and accustomed places." Some of those places, flooded by dams for hydroelectric projects, have been replaced by five "in-lieu" fishing sites in the Bonneville and The Dalles pools. Additional in-lieu fishing sites are being developed by the Corps of Engineers.

Indian lands also include trust lands owned by the Federal government and administered by the Bureau of Indian Affairs (BIA) for the exclusive use of Indians. Indian trust and Tribal lands are managed for a variety

[4] The two Strategies are based on the Draft SOR EIS issued in July 1994. The Strategies are under reconsideration and revision; for current developments, see section 4.3.4.3.

of purposes by the BIA or the Tribes. Trust assets include lands, minerals, hunting and fishing rights, and water rights. The United States has a trust responsibility to protect and maintain such rights, and to deal with the Tribes on a government-to-government basis.

Storage

Storage of water behind dams may occur at several levels: maximum operating pool (highest operating level), minimum operating pool (lowest level within the normal operating range), and minimum irrigation pool (lowest level that can meet irrigation withdrawal needs; a characteristic of John Day reservoir only).

Storage of water can have a number of *benefits*. Water stored during a season or from one year to the next can provide a "bank" for dry years, when less snow falls and melts to refill reservoirs. More water can then be made available for irrigation, navigation, and power production. Relatively inexpensive hydro power can reliably be produced to supply regional needs when the load occurs, with less need to buy more expensive power from elsewhere. Storage capacity also provides flood control: high flows that might otherwise cause flooding can be caught and then released in quantities and at intervals that do not threaten communities or resources downstream, a social and economic benefit.

When sudden or extended drafts of water are delayed or do not occur at all, there is less opportunity for erosion and slumping of soils along the sides of the reservoir. When water is retained later into the year and reservoir pool level fluctuation is minimized, more stable conditions result for fish living in the reservoirs and for wildlife that depend on the wetland and riparian habitat bordering reservoirs for foraging and nesting. (Some reservoirs, especially storage reservoirs, have such steep sides that little valuable habitat borders them; others support more wetland/riparian habitat.) Greater pool surface provides better habitat for waterfowl; islands remain isolated from shorelines and thus sheltered from predators. Benthic organisms that grow in shallow-water conditions and provide a food supply for fish can grow under steady-state conditions. Steadily maintained higher pool elevation provides access to in-flowing rivers and streams up which some species of fish swim to spawn.

Extended storage also benefits recreation at upstream reservoirs by providing stable bodies of water that encourage leisure-time activities such as boating, fishing, and sightseeing, which can bring associated tourist income to the area. If, however, downstream flows are not stable, fixed-elevation facilities can become unusable; submerged objects downstream from reservoirs can become a greater danger to windsurfers or boaters; and fishing success may change.

With a more consistent water level in reservoirs, cultural resources near or below shoreline are not exposed to the fluctuations in water level that erode and can destroy the sites/artifacts themselves; they are also not exposed to freeze-thaw cycles, to disturbance, or potential vandalism. Reservoirs kept full during the growing season (April - October) provide maximum benefits to those farmers who use pumps to withdraw water from projects to irrigate their crops and provide their livelihood: water is available and the pumps can function successfully. If reservoirs are kept at or above minimum operating pool, then shallow draft navigation throughout the river system and log transport across Dworshak Reservoir can continue for the full commercial season, another economic benefit.

There are also *drawbacks* to high or extended storage levels, or to storage at times when water is needed downstream for other purposes such as flows for fish migration. If reservoirs are kept full through the winter, there may not be enough "space" to store snowmelt and prevent flooding. If water is not released to flow through turbines downstream, power production is diminished and becomes more costly because it depends on the amount of water flowing into the reservoir from upstream. If flows are not sufficient, either alternative generation sources have to be built or power purchased from elsewhere.

Reservoirs maintained at a high or extended storage mode can slow the passage of juvenile anadromous fish through the reservoir itself, as well as make their passage downstream in river reaches slower and more difficult. Anadromous fish undergo a process called "smoltification" which sends them downstream to the ocean and prepares them for life in saltwater; the condition does not last indefinitely and, if the fish are delayed too long, they may not be able to make the biological transition. Slower times downriver may also mean increased opportunity for predators or disease to kill fish.

Reduced downstream flows can also affect resident fish living in the downstream reaches. Shallower water becomes warmer, a condition that encourages growth of benthic organisms on which fish feed and thus growth of fish as well. However, some fish—such as trout—grow best under cooler (and deeper) water conditions.

Release

Release or drafting of water from behind dams for power production occurs in two primary ways. At storage projects, much larger volumes of water are released, resulting in pool level changes of up to 68.3 m (224 ft) at a specific project. At run-of-river projects, water is passed along in flows, creating daily fluctuations in pool level of 0.9 to 1.5 m (3 to 5 ft) (gradually lower in the daytime as more water is passed through for power production; gradually higher at night as the pool refills).

Drawdown, one of the components in SOR strategies, affects run-of-river projects not by changing the fluctuation but by setting the acceptable range of pool elevation considerably lower than at present (for instance, where current operations may range between 244.3 and 246.0 m (733 and 738 ft) at a project, drawdown may change the range to 235.0 and 236.7 m (705 and 710 feet). Flow augmentation adds water from storage to increase river flows: the goal is to get fish through the reservoirs and rivers *between* dams. Spill is the release of water over the dam spillway(s). Its purpose is to attract fish to safe passage *past or over* dams (avoiding passage through turbines).

Release of water through drafting offers a number of *benefits.* It is regularly used today to augment river flows in fall and winter to produce power when it is needed. Drafting is also used to reduce water levels in reservoirs before snowmelt begins so that there is reservoir storage space to use for flood control.

When the level of water behind the dam is reduced through drafting or drawdown, the velocity of the river water increases through the reservoirs. Increased velocity may help juvenile anadromous fish migrate through the reservoir more quickly. Where drawdown lowers the pool surface elevation to a level that essentially removes the impoundments behind a series of run-of-river dams, conditions begin to return to those of a "natural river." Anadromous fish in-river survival rate would generally improve so long as direct passage were provided (for instance, the dams were essentially removed and lower-level outlets substituted). Some believe that such actions may reduce or eliminate the need for transporting fish. Long-term water quality could improve, keeping water temperatures downstream lower and reducing levels of dissolved gas which can kill fish (see Spill, below).

However, there are also *drawbacks* to major releases of water through pool fluctuations caused by drafting or drawdown. Shorelines are exposed; soils erode and slump; and large amounts of sediment may initially move downstream. Cultural resources located along the reservoirs can be damaged, through site erosion, human disturbance, vandalism, and freeze-thaw cycles in exposed sites. Drawdowns or drafting within a reservoir can disrupt and compress resident fish habitat, preventing access to in-flowing rivers and streams up which fish ascend to spawn, drying out eggs, stranding young in backwater pools, and drying out food supplies. As water levels change, the acreage of wetland and riparian habitat changes: plants are drowned or dried out, and exposed sand and gravel create a barren drawdown zone which can leave some wildlife (such as nesting waterfowl) more exposed to predators. Wildlife habitat and food sources in lower river reaches can be destroyed by increased flows from drawdown, affecting waterfowl, shorebirds, aquatic furbearers, and so on.

If pool levels at run-of-river projects are drawn down below the current minimum operating range, navigation locks, fish ladders, irrigation pumps, and other equipment cannot operate without modifications. With significant drawdown under some SOSs, there still might not be enough water available for all irrigators in some years, and farm income could drop. As less water becomes available to produce inexpensive hydro power, wholesale rates could rise significantly, and backup generation resources could be required, carrying with them their own set of environmental impacts, such as air pollution or land use changes from construction and operation of CTs.

Recreational opportunities associated with reservoirs are generally reduced as water levels fall: fixed-water-level facilities become unusable below certain pool levels. There is an associated economic consequence for local communities benefiting from reservoir-based tourism. Reduced pool level can restrict or preclude shallow draft navigation if water levels do not permit sufficient draft or if locks are inoperable in spring and summer, the major times for commercial activity on the river. Logging transport via reservoir (at Dworshak) can be reduced as water levels fall. Port activity may shift elsewhere; shipping would have to be rescheduled or carried out by other modes of transportation. These impacts have socioeconomic consequences for both cost and quality of living.

<u>Flow augmentation</u> provides *benefits* primarily for anadromous fish migration downstream. It takes two forms: release of specific amounts of water from reservoirs and lakes, or release to achieve certain targets—levels of water or rates of flow—in downstream river reaches. Flow augmentation offers the possibility of moving juvenile anadromous fish more quickly (and potentially with less mortality) downstream to the ocean. Higher spring flows could nourish additional habitat along river shores downstream. Greater flows might also benefit spawning for the Kootenai River white sturgeon, a species listed under the Endangered Species Act.

Flow augmentation has *drawbacks* for a number of other resources, however. Under some SOSs, in drier years, some reservoirs might have to be emptied significantly, leaving broad bands of barren drawdown zones. Resident fish populations in these bodies of water could thus be reduced significantly, with a smaller habitat area and reduced food supply as benthic organisms dry out. Water temperature on the surface of the pool generally rises in the absence of nearby overhanging vegetation. Wetland and riparian habitat associated with reservoirs can dry out, reducing cover and forage for wildlife, including waterfowl, nesting birds, and aquatic furbearers. Downstream, higher spring flows can, in some reaches, drown riparian habitat and reduce its use. Chances for pool refill in a following, dry year can be reduced, extending possible negative impacts on wildlife and fish from one year into the next. Recreation opportunities also diminish where fixed-elevation facilities such as boat ramps cannot be operated when water falls below a specified level, and as reservoirs become less attractive areas to visit. There would be corresponding economic consequences for nearby communities.

Flow augmentation in the spring and summer (when juvenile fish migrate to the ocean) requires storing more water in the winter, a time when it would be most valuable for use as a generating source for electricity. As flow targets are increased, the match between power loads (need) and hydro power supply worsens, and more power must be supplied from other, possible more costly sources with their attendant impacts on air or land. Wholesale rates for power are likely to increase as flows are increased. When water levels of storage projects are lowered more often, the chances of a complete refill each year are lessened, with consequent effects on power production for the succeeding year (including the need for additional backup resources).

Finally, <u>spill</u> provides *benefits* by releasing water over and around dams to channel juvenile anadromous fish away from turbines and downstream more quickly. If these fish move more quickly to the ocean, they are exposed for shorter times to predators and are more likely to make a successful physiological transition to their salt-water adaptation.

However, spill has its *drawbacks* as well. Heavy spill can super-saturate the water with nitrogen, causing "gas bubble disease," which may kill migrating juvenile and adult fish. High spill in spring may also reduce Snake River adult spring chinook passage by distracting them away from the fish ladders and toward the spill area, which provides no passage upstream. Spill represents a lost opportunity for power production, increasing potential power costs by requiring that lost hydro generation be replaced using other types of generation. The shift of available water from reservoirs under spill can also create impacts similar to those for flow augmentation, above.

Finally, both storage and the variations on release may affect the ability of Indian Tribes to exercise their reserved rights. Issues that particularly concern Tribes with respect to the SOR include treaty rights, impacts on fishing, and the protection of graves and cultural resource sites. System operations described in the SOR could affect anadromous and resident fish and wildlife, regarded as trust assets, with possible direct influence on fishing sites. The Tribes consulted in the SOR process felt that it would be increasingly difficult for the U.S. government to meet treaty and trust responsibilities tied to issues of hunting, fishing and gathering capabilities, and to damage to cultural resource sites. The SOR EIS is fully examining the potential impacts of the SOS alternatives on treaty rights and trust assets.

4.3.4.3 Impacts From Draft SOR Strategies "Current Operation" and "Coordination Act Report Operation"

"Current Operation" (SOS 2c) was the SOR's "No Action" alternative: that is, it most resembled current river operating strategy in place when the Draft SOR was being developed.[5] It included Water Budget flows and up to 3 million additional acre-feet of flow augmentation to assist anadromous fish migration.

"Coordination Act Report Operation" (SOS 7a) provided increased flow augmentation, higher spill, and Snake River drawdown in an effort to construct a package of options that increased amounts and velocity of water flowing through reservoirs and rivers, and thereby improved survival of anadromous fish.

These "alternative futures" are examined in the Business Plan EIS as the two ends of a range of impacts for business consequences: SOS 2c would have the least severe impacts on power production; SOS 7a the most.

Current Operations

Soils/Water

Moderate-to-severe soil erosion and mass wasting from drafting would continue, as currently, at storage reservoirs. Erosion at John Day and lower Snake River projects would increase in the short term; erosion would accelerate slightly at Brownlee (see figure 4.3-5 for location of hydro projects). There would be no significant sediment transport. Gas supersaturation would be reduced in the mid-Columbia reach, but increased somewhat in the lower Snake and Columbia Rivers as this strategy continues to be carried out.

Fish

Survival rates for juvenile anadromous passage and adult returns would fall in the middle of all SOR alternative strategies. With juvenile transportation, this SOS would have one of the higher survival rates. Conditions for some resident fish would be worsened: Dworshak kokanee and smallmouth bass, Brownlee smallmouth bass, and other warmwater fish. More shallow drafting would increase the probability of refill in Lake Koocanusa, resulting in a slight increase in kokanee growth (due to better food supply). However, conditions for resident fish elsewhere would remain the same. The chance of spawning of the Kootenai River white sturgeon (last documented spawning in 1974) would be very low, as increasing spring/summer flows believed to be associated with spawning success would seldom occur. This alternative would produce the lowest levels of aquatic productivity and fish growth at Hungry Horse, which supports a healthy population of westslope cutthroat trout and bull trout. Drafting at Lake Pend Oreille would force shore-spawning kokanee to spawn in less suitable areas in fall; they could also block access to river spawning grounds for other species. Drafting in winter and spring could dry out eggs, affect spawning success of warm water species (bass) in shallow waters, and strand the young. At Lower Granite reservoir, however, smallmouth bass habitat would benefit from more stable reservoir elevations in spring/summer.

Wildlife/Vegetation

Wildlife populations would continue their long-term downward trend; nesting waterfowl productivity at John Day would be slightly reduced as water levels are lowered. Lake Umatilla, which harbors one of the largest summer populations of waterfowl, would be down 0.3 m (1 ft) during April-June, reducing pool surface. This SOS might also reduce breeding duck and Canada goose numbers slightly. Large seasonal drafts from storage projects would continue to restrict wetland areas to current levels. Late winter and early spring drafting could expose significant amounts of shoreline at storage projects; there would be minimal shoreline exposure at run-of-river projects compared to past practices.

[5] Although it represents "No Action" (no change from current operations), impacts reported in this discussion will note that some effects will be "better" or "worse": this is because the current strategy has been in place only a few years, and consequences over time will continue to increase or decrease in response to those strategies.

Recreation

Historical levels of recreational use would be slightly less than that experienced under typical historic conditions (pre-Water Budget and flow augmentation). Grand Coulee would be fully operational through the summer, but some Lower Granite facilities would not be usable during periods when the reservoir is operating at minimum pools.

Flood Control/Navigation/Irrigation/Power/Economics

Expected flood incidents and damage would not be likely to change. Costs of flood damage are estimated at about $3.3 million. Normal conditions would be expected for shallow-draft navigation, and a slightly shorter operating season for Dworshak log transport. For power, wholesale rates would continue at today's level. All irrigation needs would be served. Total system (economic) cost would be about $1.094 billion. SOS 2c would be the least-cost option.

Native American Concerns

Down-river Indian Tribes would face diminished populations of salmon (Burns Paiute Tribe, 1994, cited in SOR DEIS, 1994), which those Tribes note are critical to fulfillment of their reserved fishing rights and to the basis of their cultural and spiritual existence. Tribes also believe this alternative would result in a decline in resident fish populations, limiting the Federal government's ability to meet its trust responsibilities for both resident and anadromous fish.

Coordination Act Report Operation

Compared with "Current Operation," this SOR alternative would combine more flow augmentation, increase in spill, and Snake River drawdown, with the goal of assisting materially in anadromous fish migration. "Coordination Act Report Operation" (SOS 7a) would reduce impacts for some resources (by comparison with near-current conditions as described under SOS 2c), but would increase impacts for more.

The reader is reminded that, since the draft EIS was released, this alternative has been reexamined and essentially replaced with a new SOS, "Detailed Fish Operating Plan," which will likely include considerably more spill, drawdowns at more projects, and drafting to meet flow targets. The analysis for this BP EIS is based on more recent figures (superseding those used for the Draft SOR EIS). Impacts described below will vary (generally increase in intensity) for the newer SOS. See Anticipated Changes to SOSs, below.

Soils/Water

Erosion, mass wasting, and sedimentation would increase substantially at Lower Granite as a consequence of flow augmentation plus drawdown strategies; much of the resulting sediment would move down toward Little Goose. However, these effects would decrease substantially at Libby and Hungry Horse because pools would be maintained at more stable elevations, as well as at Dworshak, where the total annual draft would decrease. Grand Coulee would experience significant erosion and mass wasting as a result of a relatively large total annual draft, which would expose more shoreline. The total dissolved gas standard at Ice Harbor would be exceeded twice as often as under "Current Operations" (139 days vs. 61 days), as a consequence of flow targets and spill requirements for McNary and lower Snake River projects, and also because Lower Granite would be drawn down an average of 7.6 m (25 ft) below normal operating pool elevation. There would be some major sediment transport downstream, through scouring from Lower Granite should be deposited upstream of Ice Harbor Dam.

Fish

Although the elements of this alternative were intended to increase potential fish survival, "Coordination Act Report Operation" would result in lower survival rates for Snake River salmon (spring, summer, and fall), with or without transportation. High spill levels account for this result: they increase nitrogen supersaturation in the Snake reservoirs and substantially increase reservoir mortality (except for summer steelhead because they are released early in April before gas levels rise). If in-river passage only is accounted for, future adults escapements would be lower than all other alternatives for Snake River spring and summer chinook stocks. Even with transport, survival of all Snake River stocks would remain below that of SOS 2c (and most other SOSs). On the other hand, survival of spring chinook stock could be highest if the assumption were made that the increased gas supersaturation from high spill levels would have no negative effect on fish. Marked drawdowns could decrease food supply in the lower Snake for other anadromous fish.

Overall, this SOS turns out to be one of the worst for resident fish production, although it is expected to provide improvements of survival for Kootenai River white sturgeon. Other conditions for resident fish are generally worse. At Lake Koocanusa and at Hungry Horse, drafting would be shorter and less frequent, so that food supply and fish growth would be improved, and refill timing would enhance access to spawning, particularly for bull trout and westslope cutthroat in Hungry Horse. At Lake Roosevelt, minimum predicted elevations would be extremely low. Fish production would be worse, with high fish entrainment, reduced zooplankton production, and low fish growth. Similarly, Dworshak would have the poorest conditions for resident fish under “Coordination Act Report Operation”: deep drafts, frequent refill failures, and high outflows, resulting in high entrainment rates of kokanee, and failed spawning for bass and other species. This SOS would be worst of all SOSs for Lower Granite, with month-to-month fluctuations in reservoir elevation, reducing spawning/rearing of bass and other fish.

Wildlife/Vegetation

At Libby and Hungry Horse projects, increased wetland and riparian vegetation would increase populations of most categories of wildlife. However, prolonged drafting of Grand Coulee would increase the drying out of the few wetlands and shallow waters, and prolong occurrences of broadband drawdown areas, reducing populations of waterfowl, non-game birds, aquatic furbearers, and amphibians, particularly in years when two separate drafts would occur during the winter/refill season (17 out of 50 years in the historical record). Early spring and summer drafts at Dworshak and Lower Granite would reduce populations of aquatic vegetation and organisms, adversely affecting most categories of wildlife at Lower Clearwater reach and Lower Granite project. There would be relatively severe declines in populations of waterfowl, colonial nesting birds, furbearers, and amphibians at Lower Granite, as water levels drop 7.6 m (25 ft) in May and June. Conditions at Lake Umatilla might improve because water levels would be raised, increasing protection against predators for waterfowl and other species which nest on islands.

Cultural Resources/Recreation

Site damage to cultural resources would increase significantly at Lower Granite: “Coordination Act Report Operation” is one of the SOSs with the greatest potential to accelerate erosion by augmenting flows. Rapid drafting of Dworshak could increase potential for land slumping on steep slopes, as water would fall below traditional pool levels, cutting new shoreline benches and exposing more land. This SOS would create the greatest overall amount of shoreline exposure at storage reservoirs (primarily Grand Coulee and Dworshak), affecting both esthetics and cultural resources. Recreational use visitation would be reduced below that for “Current Operation” as reservoirs are drawn down.

Flood Control/Navigation/Power/Irrigation/Economics

This SOS would have the highest flood risk of the SOS alternatives (primarily in upper Columbia tributaries), because following biological rule curves would keep reservoirs higher to benefit resident fish, reducing the ability to absorb flood runoff. Average annual damages are expected to be about $5.0 million. No shallow draft navigation would be possible on Lower Granite for 4 to 5 months during drawdown. The Dworshak log transport would have a much shorter operating season, compared with “Current Operation.” Total navigation costs would be about $2.2 million more than under SOS 2c. The Gilford Ferry on Lake Roosevelt would be inoperable for at least 1 month each year, and possibly more.

Energy production would be significantly reduced by high spill and turning off turbines. Annual system generation costs would be about $467 million more than under “Current Operation” (if CTs are constructed to replace lost hydropower); about $325 million more than SOS 2c if replacement power were purchased. Wholesale rates would increase 16 to 21 percent, assuming such rate increases could produce revenue to pay replacement power costs.

In critical water years, irrigation pumps would not be able to keep up with irrigation demand, and some acreage would be without sufficient water as a consequence of the unusually low lake level at Grand Coulee. Economic impacts would increase over “Current Operation”: there would be increased costs/reduced benefits primarily for recreation, anadromous fish, power, and flood control and associated impacts from reduced employment. The cost of operating the power system is by far the largest element of any change. Total annual system cost would be $492.8 million higher than SOS 2.

Native American Concerns

Anadromous fish appear to fare slightly worse or the same as under “Current Operation.” Impacts on wildlife habitat affecting hunting rights and on vegetation conditions would vary from reservoir to reservoir. Wildlife resources would improve at Libby, Hungry Horse, Lake Umatilla, and along the Hanford Reach, but wildlife populations would decrease in the Lake Roosevelt area and at Lower Granite.

Anticipated Changes to SOSs

After publication of the SOR DEIS in the summer of 1994, a public comment period was held. That period has since closed, and the SOR interagency team is working on the FEIS. Through response to comments and further analysis, the several SOSs examined in the DEIS are being revised; in some cases new SOSs are replacing draft versions. The descriptions below represent changes as they relate to “Current Operation” (SOS 2c) and “Coordination Act Report Operation” (SOS 7a). The reader should bear in mind that the SOR FEIS is on a later schedule than this BP EIS, and that the descriptions below represent the direction of change but possibly not the final form of these SOSs.

- **SOS 2c (“Current Operation”)** has been supplemented by the addition of a new alternative labeled as **SOS 2d (“1994-1998 Biological Opinion”)**. It does contain minor changes from SOS c, and better reflects current practices, particularly in light of ESA consultations that occurred in 1994. It includes 4 MAF of flow augmentation rather than 3 MAF.
- **SOS 7a (“Coordination Act Report Operation”)** is being replaced by **SOS 9a (“Detailed Fish Operating Plan”)**. Although the measures would be the same, differences in degree of implementation and in impact are considerable. Drawdowns to near spillway crest would occur at all four lower Snake projects (Ice Harbor, Lower Monumental, Little Goose, and Lower Granite). The impacts described above for SOS 7a at Lower Granite would therefore be likely to apply to all four projects, instead of at Lower Granite only. The high spill projected for Lower Granite and its consequences for gas supersaturation (anadromous fish mortality) and loss of power production potential would apply to all eight projects (at 120 percent daily average total dissolved gas). Finally, Hungry Horse and Libby would be drafted to meet flow targets downstream rather then using specific elevations designed to benefit resident fish and wildlife. This would reduce potential improvements for residential fish at Hungry Horse and Libby reservoirs and result in lower pool elevations sooner in the season and for more of the summer. There would be no fish transportation.

The current preferred alternative for the SOR EIS is based largely on the Biological Opinions released by the NMFS and the USFWS in March 1995. Its impacts for power production would fall in the middle of the range of impacts described above.

Summary

The discussion above has been provided to help the reader understand how the decisions in the SOR process may affect the business course BPA chooses for the future. That business course is the proper subject of this BP EIS. Issues centering on how operating the river will affect fish and wildlife survival and enhancement, trust obligations, access to salmon for treaty issues, and cultural resource impacts are fully analyzed in the SOR.

4.4 Cumulative Market Responses and Environmental Impacts of Alternatives

The following discussions address the cumulative market responses and environmental impacts of the alternatives addressed in this EIS. Market responses and impacts are first addressed under current hydro operations (4.4.2), followed by an illustrative numerical assessment of impacts (4.4.3). Market responses and environmental impacts are then assessed under DFOP hydro operations (4.4.4).

4.4.1 The Marketing Context

4.4.1.1 Evaluation of Alternatives in a Dynamic Electric Power Market

The rapid changes occurring in the electric power market (see sections 1.1 and 3.5) are a major factor in the need for BPA to evaluate its business policies. These changes also present significant challenges to the evaluation of market responses or environmental impacts. Since the Draft Strategic Business Plan and initial Draft Business Plan EIS were released in June 1994, the electric power market has continued to evolve in a manner unprecedented for the electric utility industry. The price of natural gas has declined, costs of new generation have declined, and many new prospective sellers have entered the PNW wholesale power market. The average cost of new generation has dropped by roughly one-quarter in the last year. With changes occurring so rapidly, it is difficult to make reliable estimates of gas prices, electricity rates, or electrical loads for the next 12 months, much less for the year 2002, the end-date study year for this EIS. Rate and load projections are subject to change from week to week to address new developments in the market. Despite this uncertainty, this EIS must try to show the effects of the different alternatives to enable readers and decisionmakers to assess their relative merits.

The key to the comparison of EIS alternatives is not the *numerical* estimates of power rates, resource amounts, or air emissions, but the relationships that determine those values. Although this EIS includes rough numerical estimates of the rate, load, resource, and environmental effects of the six alternatives, it is clear that these values, especially in relation to the dynamics of the market, are only a “snapshot” in time, an illustration of the relationships among the market influences; they are not conclusive as to the ultimate outcome.

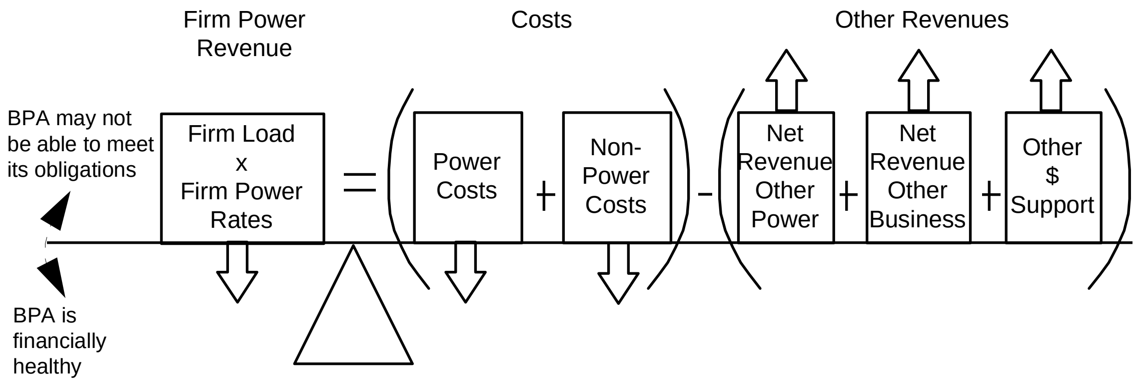
4.4.1.2 Marketing Relationships Affecting the Balance Between BPA’s Costs and Revenues

Two relationships dominate the effects of the six EIS alternatives. They are:

- <u>the effect of BPA’s rates</u>, as compared to the price of alternative power supplies, on customers’ decisions on whether to buy from BPA (and therefore on BPA’s firm loads); and
- <u>the effect of the terms of BPA service</u> on customers’ decisions on whether to buy power from BPA.

In brief, if BPA’s firm power rates are close to or higher than the price of alternative power supplies, BPA’s firm loads will decline sharply, as more and more customers choose to buy their power from suppliers other than BPA. Increases in BPA's costs will push BPA's rates upward, and increase the likelihood that BPA's firm loads will go to other suppliers. In addition, terms of BPA service that are perceived as burdensome to customers can accelerate the decline in BPA's loads, while more appealing terms can slow it down. These two relationships are the foundation for the estimates of rates, loads, and resources that are discussed in sections 4.4.2 through 4.4.4 below.

One way to conceptualize these relationships and some of the factors that influence changes in those relationships is to consider a simplified equation that summarizes BPA's marketing situation. BPA is able to meet its revenue requirements if this equation balances. The equation is as follows:



The parts of this equation are explained below.

Firm Power Rates

First, firm power rates are on the left side of the equation above because they are make up the largest share of BPA's revenues, and BPA's fiscal condition depends heavily on its success in power sales. Firm power revenues are affected by a number of factors. The most important concern is the concept of maximum sustainable revenues.

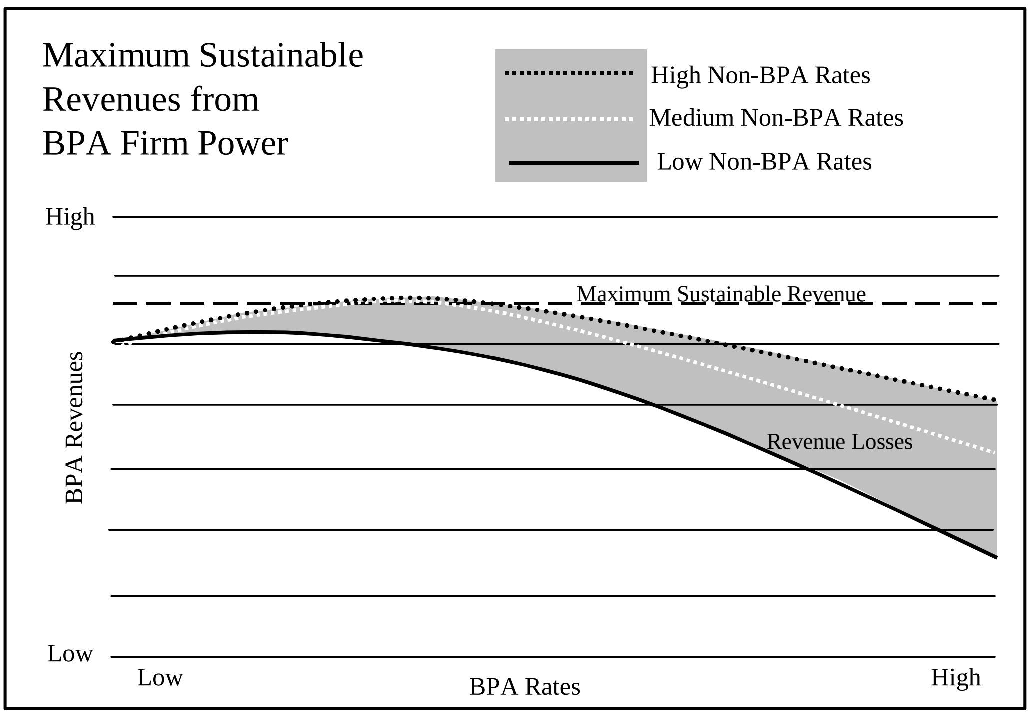
Maximum Sustainable Revenues

In the competitive power market, when BPA's rates are close to the cost of alternative power supplies, there is a point at which an increase in rates will not increase revenues. This is because the potential increase in revenues from the higher price is affected by load loss as customers look elsewhere for cheaper power. This means that the amount of revenue BPA can generate from firm power is limited by the market price for power. BPA cannot pay additional costs simply by raising rates, if rates will go above the maximum sustainable revenue level: the rate level at which BPA's revenues are highest.

In the past, when costs have increased, BPA has been able to increase firm power rates to pay for increases in its revenue requirements. Customers may not have welcomed rate increases, but the cost of BPA power even *with* rate increases was historically well below the cost of power from other suppliers. BPA's rate increases, therefore, did not significantly affect customers' willingness to continue buying power from BPA. Now, however, a competitive market has emerged for electric power, and non-BPA suppliers are beginning to offer comparable power products at prices comparable to BPA's rates. Hence, increases in BPA's rates will provide additional revenue only to the extent that customers continue to buy power from BPA.

The maximum sustainable revenue level will change as the market price for power changes. BPA firm power rates might remain constant, but if the market price for power (and therefore the maximum sustainable revenue rate level) drops below BPA's firm power rate, BPA will lose loads and revenues will decline (see figure below). Given the current market, BPA estimates that the rate level for maximum sustainable BPA revenue is roughly 29 to 33 mills/kWh for firm power.[1] There are indications in the electric energy market that the cost of non-BPA power will decline, due to a combination of increasing efficiency in new CTs, abundant supplies of natural gas, and intense competition among utilities, marketers, and IPPs, to the point where some power marketers have acknowledged a willingness to operate at a loss for some years in order to secure a share of the Pacific Northwest market.

Some customers are more sensitive to price than others; some will move load away from BPA at lower prices than others. Aluminum plants and similar flat loads can be served at lower cost than fluctuating utility loads, because they do not require services to match power deliveries to changes in loads. As a result, other suppliers can offer lower prices to serve DSIs, and the rate level where significant portions of BPA's DSI loads shift to non-BPA power supplies is lower than the maximum sustainable revenue rate level for utilities.



[1] The rate level for maximum sustainable revenue is declining and is now about 25 to 28 mills/kWh.

Tiered Rates

Another influence on firm power revenues is tiered rates. With a tiered rate structure, revenues depend on customers' willingness to purchase portions of their power at two different prices. If Tier 2 costs more, some customers will buy less at that level; some may not buy any, especially when there are competing suppliers who may offer power at prices near or below the Tier 2 price. If the Tier 2 price is set based on the marginal cost of power and that cost is close to the average cost of power, then a tiered rate structure would have little effect—the overall average rate would be the key to customers' decisions about load placement. As with all market power prices, BPA's customers' decisions whether to purchase power under a tiered rate structure will also affect BPA's firm power revenues.

Energy Resource Costs

Just as firm power produces the bulk of BPA's revenues, energy resources represent the bulk of BPA's costs. This element includes the costs of FCRPS projects assigned to power production, costs of energy conservation programs, BPA's share of the costs of the WPPSS generating projects, the costs of other resources BPA has acquired, and the costs of power purchases BPA makes to fill out its power needs. Most of these costs are long-term obligations with fixed payments that do not change over time. They do not decrease when BPA's power sales decrease. BPA's power sales must, by statute, provide the revenue to pay for these costs.

Even though the marginal cost of new generating facilities has been dropping in the last few years, BPA's costs will remain about the same as they are now, because BPA continues to meet most of its power requirements from existing facilities, and is acquiring little if any of the new low-cost generation. Aside from reduced costs available to BPA by the reinvention of its energy conservation programs, the only significant energy resource cost savings to BPA will come from lower prices for power purchases, which are driven by the market price. In general, falling costs for new power resources will sharpen the competition for BPA's loads, but will not reduce BPA's existing energy resource costs.

Net Revenues From Other Power Products and Services

Other power products and services besides firm power contribute to BPA's total revenues. Historically, BPA has frequently made sales of capacity or surplus firm power, particularly during the power surplus of the early 1980s. BPA's proposed action includes offering "unbundled" products and services in the electric power market. Products and services will be offered and priced separately so that customers may choose only those products they need, rather than accept a predetermined package of services. Unbundling would allow customers to avoid buying services they don't need or use; it would also discourage inefficient use of valuable services that are embedded in larger packages of services.

Because BPA has limited experience in the sale of unbundled services, and would offer unbundled products at cost-based rates initially, the revenue potential of unbundling is limited until the competitive market is functioning and buyers and sellers can establish the market value of the separate services. As with firm power, the revenue BPA can obtain from these products and services is limited by the price and availability of comparable products from other suppliers, i.e., the marketplace. For the near term, revenues from unbundled products and services are not likely to reduce significantly the revenue BPA relies upon from firm power sales.

Net Revenues From Other Business Lines

BPA also has or is developing other marketing capabilities that can produce substantial revenues. BPA has reorganized into three business lines: power, transmission, and energy services. Firm power and the unbundled products and services discussed above are within the power business. Transmission produces substantial revenues for BPA, and energy services has significant promise for the future. However, transmission revenues are limited to cost recovery, and energy services are not expected to produce significant supplemental revenues for several years.

Bulk power transmission regulations have changed significantly in recent years to promote competition in the power business. Transmission rates are regulated so that transmission users have access to available transmission, while transmission owners are allowed to recover their costs without exploiting their control over access to power markets. For BPA, these access provisions mean that BPA will be able to set rates to recover its transmission costs, but also that BPA's dominant position in the PNW transmission system will not be a means to enhance BPA's revenues.

Energy services is a broad category that includes energy conservation and DSM programs, telecommunications, engineering services, environmental consulting, laboratory services, hazardous waste management and cleanup. BPA could market these and other services based in most cases on expertise and capabilities BPA originally developed for its own use. These services could become a sizable share of BPA's business over time. However, BPA is only starting to develop these services: they do not yet produce revenue, and their revenue potential will be uncertain until BPA has accumulated some experience in marketing them.

Costs of Non-Revenue-Producing Activities

BPA also pays the costs of activities that, while beneficial, do *not* produce revenue. These activities include fish and wildlife restoration and enhancement actions, research and development on energy resources and transmission, and other beneficial efforts that cannot produce revenue.

Fish and wildlife enhancement efforts, as mandated under the Northwest Power Act, are a major part of these costs. Due to the continuing decline in vulnerable salmon populations, fish and wildlife agencies are developing plans which call for BPA to fund additional measures to avoid extinction of critical salmon runs and to maintain and increase populations of existing runs. Because BPA has a statutory mission to restore Columbia River salmon runs, and because efforts to date have not succeeded in reversing their decline, these costs are certain to increase, and are unlikely to decline until salmon runs show significant improvement. The costs of other non-revenue-producing activities may not be as certain, but because they are relatively small by comparison to BPA's fish and wildlife costs, they will have minor effects compared to BPA's total costs for all non-revenue-producing activities. These costs can be expected to increase in the near term and then continue at increased levels for the foreseeable future.

Other Financial Support

Finally, other financial support may offset some of BPA's costs. Because BPA is a Federal enterprise directed to pay its costs from ratepayer revenue, outside financial support has not been considered in BPA's financial planning until recently. However, increasing costs for fish and wildlife restoration, coupled with increasing competitive pressure, as discussed above, have raised the prospect that ratepayer revenues may not be enough to pay all of BPA's costs. Although BPA has paid the full costs of the program in the past, under section 4(h)(10)(C) of the Northwest Power Act, BPA's obligation to pay the costs of the regional fish and wildlife enhancement program is limited to the share of the FCRPS costs that are attributed to power production. In 1994, BPA was reimbursed for costs related to emergency flow augmentation and spill. Section 4(h)(10)(C) could be the basis for additional credits or funding for BPA's fish and wildlife costs in the future.

Conceivably, budget appropriations or other support might also be used to offset some of BPA's costs, given an adequate showing that the costs were necessary and that BPA's best efforts would not be sufficient to generate the needed revenues. Considering the well-known public sentiment opposing increases in government spending, however, this type of support for BPA's activities must be considered unlikely.

4.4.1.3 Overall Significance of the Marketing Equation in Relation to EIS Alternatives

BPA's choice among the EIS alternatives will affect its ability to maintain balance in the face of both the trend for costs to increase and loads to decline.

If BPA's rates under a given alternative are relatively higher, load losses are increased, because BPA is more vulnerable to having the price of alternative power supplies undercut BPA's price. If the terms of BPA service are relatively more burdensome, then more customers will decide not to buy from BPA regardless of price. Each alternative affects these relationships differently. Depending on BPA's costs and the terms of service under each alternative, BPA's loads and its prospects for maintaining balance between revenues and costs vary among the alternatives.

4.4.1.4 How Marketing Relates to the Development of Power Resources and Environmental Impacts

BPA's total firm power loads reflect the eventual result of customers' choice of supplier. A firm load shift away from BPA will have some predictable environmental effects.

Based on current trends in power generation technology and in the market, virtually all of the power replacing BPA firm service will come from new CTs, subject to resource development constraints imposed by public utility commissions (PUCs) or state siting authorities. Suppliers competing with BPA will build CTs to run as baseload plants to serve firm load that they have drawn away from BPA. If BPA firm loads decline below historical levels, then resources BPA would have used to serve those loads will become surplus.

Hydro generation will virtually always generate power as water is available, so the effect of a BPA surplus is to free up hydro generation from firm load service to displace other resources. The presence of a BPA firm surplus in the region would lead to decisions about which resources to displace. These decisions would be based almost entirely on economics. The highest-cost generation in the region would be displaced first, and then lower-cost until all of the surplus firm hydro generation is in use.

In the analysis of resource operations for this EIS, each of the alternatives would result in a different "stack" of resources. From most to least likely to operate, these would be existing hydro, existing thermal resources that must run (including cogeneration, renewable resources, geothermal generation, and baseload coal and nuclear plants), new efficient CTs, and existing higher-cost thermal resources (including both older CTs and some coal generators). The more new CTs built under a given alternative, the less the existing higher-cost thermal resources would run. In general, impacts of these operations, particularly on air quality, are lessened by the displacement of higher-cost thermal generation with power from new CTs, because the greater fuel efficiency of new CTs also means they produce lower air emissions per unit of power.

A higher-flow hydro operation would alter this relationship by reducing the amount of firm hydro generation available to BPA. If BPA continued to serve its current loads, it would have to replace the lost hydro capability, mainly with power purchases or new CT generation. If BPA lost load to competing suppliers, they could be expected to serve the loads with new CTs. Either way, the effect of the hydro operation would be to increase firm loads served by CT generation, and to create the same type of opportunity for new CT generation to displace higher-cost thermal generation as described above.

Environmental impacts of these load changes would be the increased impacts of new generation developed, minus the reduced impacts from displacement of existing generation that would otherwise operate. Specifically, the impacts of CTs would increase, while the impacts of higher-cost thermal generation would be reduced. On the whole, total impacts of generation would probably be reduced because the new CTs that would operate are more fuel-efficient and cleaner than the displaced higher-cost older generation.

4.4.1.5 Response to Revenue Imbalance

The equation above shows that if BPA firm loads drop, BPA would have to reduce other costs or increase other revenues to maintain balance. Conversely, if BPA costs increase, BPA revenues or other financial support would have to increase to maintain balance. Current information about market trends and BPA costs indicates that BPA loads are likely to decline if the market price of alternative resources continues to fall; that BPA costs are likely to push the equation out of balance; and that both are beyond BPA's direct control.

BPA could choose to address the imbalance through one or more response strategies. Chapter 2 (section 2.5) briefly describes response strategies BPA could pursue if its costs exceeded its maximum sustainable revenues.

Response strategies fall into the following three general categories, based on how they affect BPA's financial condition:

- Increase BPA revenues
- Reduce spending for BPA's activities
- Transfer BPA spending to other entities.

Strategies vary in their effect on BPA's ability to meet its costs, and in their feasibility. Some might mitigate a significant share of the increased spending, but would be controversial, while others might make a smaller difference in BPA spending without triggering contentious debates among BPA's customers and constituents. Some might require changes in law or executive policy. BPA's goal in selecting among available response strategies would be to achieve a cumulative change in costs, revenues, or spending responsibilities that is enough to enable BPA to meet its financial obligations, including Treasury payments, while continuing to compete in the West Coast and regional electric energy markets.

4.4.2 Market Responses and Impacts of Alternatives Under 1994-1998 Biological Opinion (SOS 2d)

The following subsections describe Business Plan EIS alternative market responses and environmental impacts assuming that current hydroelectric operations continue approximately as they are today. (See sections 2.1.6, 3.6.2.1, and 4.3.4.3.) Section 4.4.4 describes how Business Plan alternatives might change under a System Operating Strategy that provides additional spill and increased flows, as well as drawdown, to aid in anadromous fish migration.

This section evaluates market responses and their associated environmental impacts in the four key areas—resource development, resource operation, transmission development and operation, and consumer behavior—for each alternative. They are based on projected market responses to each of the individual issues that make up the alternatives. In general, the responses and impacts are driven by BPA's customers' reactions to the combination of several factors: BPA firm power costs (and customers' perceptions of the risk that those costs will increase), the perceived benefits or burdens of doing business with BPA, the prices BPA charges for its products and services, the particular BPA contract terms available in each alternative, and the options various customer classes have for obtaining power or transmission services elsewhere.

The text below uses numerical analysis to demonstrate the differences among EIS alternatives, making assumptions about rates, loads, energy resources, and environmental impacts. However, because the electric power market is changing rapidly, these results cannot be considered to be definitive. For example, since the original analysis for the BP EIS was completed in June, 1994, gas prices and CT costs have declined significantly. These and other business environment changes as described in chapter 1 (section 1.1) and chapter 3 (section 3.5) make predictions of specific rates, prices, and other numeric results, uncertain. Numerical analysis serves, however, to illustrate the principles and relationships discussed in the previous section (4.4.1).

The following is the logic for the analytical results explained below:

- Assumptions about expenditures and loads provided the basis for projecting average PF and IR rates.
- For the BPA Influence, Market-Driven, and Short-Term Marketing alternatives, tier size and price assumptions were used to generate rates for each tier of a two-tiered rate structure.
- These rates then were used to estimate two types of price effects on utility loads:
    - √ Utility decisions to purchase non-BPA power instead of BPA requirements service
    - √ Consumer responses to retail price, including fuel switching and price-induced conservation.

- For each alternative, estimates of market responses took into account the modules built into the alternative (i.e., the “intrinsic modules” identified in section 2.3).
- BPA resource acquisitions, and resource acquisitions by the rest of the region, including conservation, were identified to serve the loads as adjusted.
- Based on assumptions about economic operation of resources, such as priorities for displacement of thermal plants with secondary hydro, a spreadsheet model calculated the amounts of power provided by BPA and other resources.
  - √ Thermal resources were divided into baseload thermal, high-cost, and low-cost. Baseload plants were assumed to run at all times except during maintenance periods; high-cost resources (typically older and environmentally worse) were the first to be displaced during periods when secondary hydro was available.
- These amounts of operation, and the amounts of aluminum DSI load, were multiplied by the typical unit impacts for major categories of environmental impacts to calculate the total impacts of each alternative. BPA estimates of environmental externality costs for NO_X, SO_X, TSP, and CO_2 were applied to air emissions to provide an estimate of environmental externalities associated with thermal plant operations.
- Transmission impacts were estimated separately based on judgments about facility development under each alternative and typical land use (right-of-way) requirements for each class of transmission line projected to be constructed.

Analytical steps are described in greater detail in Appendix C. Additional planning uncertainties which could affect the results follow the analysis of the alternatives (section 4.4.5).

4.4.2.1 Status Quo (No Action)

In this alternative, existing rate and contract terms remain in place. BPA would offer utilities and DSIs new firm contracts comparable to current contracts, and would renew existing rate designs, including the Variable Industrial Rate for DSIs. BPA would not respond to the availability of competitively priced alternatives to BPA power.

Features of this alternative include:

- **Average PF** rate in 2002 would be approximately 32 to 36 mills/kWh (nominal $).
- BPA's **utility loads** would be **reduced** over **1,400 aMW** compared to 1995 Rate Case estimates, primarily due to customers choosing non-BPA generation.
- BPA's **DSI firm loads would decrease** by about **800 aMW** due to DSI use of other sources of power (self-generation and purchases from other utilities or IPPs).
- BPA would continue with conservation programs and resource acquisitions as identified in the 1992 Resource Program, leading to a **BPA firm power surplus on a planning basis of over 1,600 aMW.**
- A surplus would allow BPA to serve approximately 900 aMW of exchanging utilities’ "in-lieu" loads.
- More CTs would be acquired regionally than in other alternatives; however, the existence of these CTs would allow surplus hydro power and CT energy to be used more often to displace existing high-cost thermal plants with greater environmental impacts than CTs (e.g., Boardman, Valmy, and Centralia coal); therefore, the environmental impacts of thermal operations would be lower than under other alternatives.

The following modules are intrinsic to the Status Quo alternative (section 2.3 describes each module):

FW-1	Status Quo
RD-5	Variable Industrial Rate
DSI-1	Renew Existing DSI Firm Contracts
CR-1	"Fully Funded" Conservation

Rates

Rate projections for the Status Quo alternative are based on the 1995 Rate Case assumptions, modified by the assumptions that define this alternative (namely, fully funded BPA conservation, existing fish and wildlife, and resource acquisition programs, and planned transmission development at embedded cost) and assuming that BPA's current rate, budget, and marketing policies would continue. Rate trends were used as inputs for the analysis of loads and of the resource development and operation market responses. As shown in table 4.4-7 (section 4.4.3), the Status Quo alternative produced the highest rates of the alternatives. The assumption that BPA programs would continue without modification despite load losses implies increased rates because unchanged program costs must then be recovered from a smaller amount of firm power sales. A countervailing influence would be the cost savings resulting from using a portion of the surplus to serve in-lieu loads of IOUs that participate in the residential exchange program. (That is, rather than exchanging BPA power at the PF rate with IOUs at their average system cost in a purely accounting transaction, BPA actually would use its resources to serve a portion of the exchange load.)

Loads

Under this alternative, BPA would lose approximately 1,400 aMW of 1995 Rate Case forecast utility loads to non-BPA generation due to price competition from non-BPA suppliers. BPA also would lose approximately 800 aMW of DSI firm loads to non-BPA generation, even though total DSI loads increase 200 aMW over the 1995 Rate Case forecast. Approximately 300 aMW of the DSI top quartile would be served by interruptible power in this alternative.

Cost/Revenue Balance

Planned spending would result in BPA rate levels above the maximum sustainable revenue level, and higher than in all other alternatives. In the long term, BPA costs and revenues would not balance. In fact, the shortfall of revenues versus costs would probably be greater than in all other alternatives.

Resource Development

BPA would have acquired resources as described in the 1992 Resource Program and as shown in table 4.4-1 below (i.e., approximately 600 aMW conservation, 500 aMW new generating resources, 50 aMW of efficiency improvements, and 200 MW of planned power purchases). The rest of the region would acquire new resources with a heavy emphasis on CTs.

Resource Operations

Under this alternative, the regional load in 2002 would be approximately 22,200 aMW, with resources totaling 23,800 aMW; all of the surplus would be Federal (see tables 4.4-8 and 4.4-15 in section 4.4.3). The DSI top quartile service would be 300 aMW. Total CT operations would be about 2,500 aMW (more than any other alternative), while coal would serve about 3,200 aMW (less than in any other alternative except BPA Influence). Under Status Quo, coal operations would be at relatively low levels because BPA would continue to have a significant firm surplus, a portion of which would be sold as surplus to displace existing high-cost thermal resources, primarily coal.

Table 4.4-1: New Resource Acquisitions: Status Quo

BPA New Resource Acquisitions - 2002	
Resource Types	**aMW**
Conservation*	600
Efficiency Improvements	50
Renewables	80
Cogeneration	100
Planned Power Purchases	200
Combustion Turbines	300
Coal	0
Total	**1,330**

REST OF REGION New Resource Acquisitions - 2002	
Resource Types	**aMW**
Conservation	690
Efficiency Improvements	80
Renewables	100
Cogeneration	0
Power Purchases	0
Combustion Turbines	1,740
Coal	0
Total	**2,610**

*Includes 49 aMW of conservation due to codes and standards already in place.

Transmission System Development, Operation, and Rates

BPA would continue to offer its current mix of transmission and wheeling products under current rate schedules. BPA would also continue to plan, construct, and operate its transmission system as it has in the past—that is, with a long-term, one-utility focus, and, overall, a very high level of transmission system reliability. It is likely that BPA would continue this role for the transmission system even if its share of regional load growth were smaller than in the past.

Currently planned additions to the interconnected transmission system in the Northwest Power Pool (NWPP) area (all of Washington, Oregon, Idaho, Montana, Utah, British Columbia, Alberta, most of Nevada, and western Wyoming) are shown in table 4.4-16 (in section 4.4.3 below).

EPA-92 may bring new influences not reflected in the projections to transmission system planning. Although in the past BPA made excess capacity on its transmission system available for non-Federal wheeling, EPA-92 may result in BPA providing transmission service to utilities and non-utility generators, and for building new transmission system capacity if needed to provide wheeling service. For new non-Federal power, EPA-92 would apply in all of the alternatives examined in this EIS.

Even considering the effect of EPA-92, this alternative would probably lead to the largest role for BPA in regional transmission system planning and high-voltage transmission construction among the alternatives addressed in this EIS. This is because BPA would continue to plan and construct transmission system additions using its existing reliability standards (which emphasize high regional reliability) and a long-term, one-utility planning focus. Transmission rates would be priced consistent with national transmission pricing policy. In other alternatives, it is assumed that BPA would relax or modify system planning criteria, and would have a smaller role in regional transmission development. As explained in section 4.2.4 above, under "Transmission System Development," a larger role for BPA is associated with more high-voltage transmission development in the short term (i.e., as shown in the "snapshot" for 2002 in table 4.4-16, section 4.4.3), but fewer overall kilometers of transmission in the long term (post-2002). Table 4.4-16 indicates that even in the Status Quo alternative, BPA would likely construct little new transmission in the 115- to 161-kV voltage class. The negative numbers for 115- to 161-kV transmission in that table indicate that BPA would build less new transmission of that voltage than it would take out of service (generally in order to upgrade to a higher voltage).

Consumer Behavior

Retail rate effects for a particular utility depend on the ratio of BPA-purchased power costs to total costs and the total kWh sales for the utility. The projected retail rate for Status Quo is the highest of the six alternatives (53 to 59 mills for a typical full requirements customer and 30 to 36 mills for a partial requirements customer purchasing 50 percent of its power from BPA). The burden would be relatively greater for consumers of full requirements customers than for consumers of partial requirements customers. Price-induced conservation and fuel switching would be minor (close to zero) compared with 1995 Rate Case projections in this alternative, because with BPA's rates higher than the market price, customers would take load off BPA in order to reduce their costs, and thus BPA's higher costs would not result in much of a retail price signal for many consumers.

Environmental Impacts

Under Status Quo, BPA would acquire more new generating and conservation resources than in all other alternatives (tables 4.4-1 and 4.4-11, and would have a substantial resource surplus. Other utilities would acquire their own resources rather than place load on BPA, and overall, the region would acquire more resources than in all other alternatives. Key environmental impacts of the Status Quo are summarized in section 4.4.3, tables 4.4-19 and 4.4-20. Air quality emissions and water consumption would be associated primarily with the operation of existing coal plants, the DSIs, new and existing CTs, and fuel switching. The negative numbers shown for air emissions related to power sales and purchases in table 4.4-19 result from the high level of displacement of existing thermal resources in the PSW by PNW secondary sales. Land use impacts would result primarily from transmission development, which is higher in this alternative than in most others; however, overall, land use impacts are comparable to other alternatives. Regional employment growth is predicted to be approximately 1.9 percent in the year 2002, as in all other alternatives.

Overall, this alternative would have slightly lower air quality impacts than other alternatives (except for BPA Influence). This is because BPA has surplus resources, which in part are used to displace higher cost thermal resources, such as Valmy and Centralia coal plants. While this alternative shows more CT acquisitions than other alternatives, because CT emissions are lower than coal, overall, emissions are reduced.

The final line of table 4.4-20 expresses environmental impacts in terms of environmental externality estimates. Air quality impacts from all sources shown in table 4.4-19 and summarized in the top half of table 4.4-20 are multiplied by the environmental externality estimates BPA developed for SO_X, NO_X, TSP, and CO_2. The results show that environmental externalities would be lower for Status Quo than for all other alternatives except BPA Influence; however, it should be noted that the maximum difference among all alternatives is only approximately 13 percent.

4.4.2.2 BPA Exercises Market Influence to Support Regional Goals

Features of this alternative include:

Program costs would continue as under the Status Quo.

- **Average PF** rate in 2002 would be about **30 to 34 mills**/kWh (nominal $). **Tier 1** would sell for about **29 to 33 mills**/kWh, with **Tier 2** at about **36 to 40 mills**/kWh.
- Compared to Status Quo, BPA's **utility loads** would **increase by 800 aMW**; however, compared to 1995 Rate Case assumptions BPA utility loads would be reduced approximately 600 aMW.
- Compared to Status Quo, BPA's total firm and nonfirm **DSI loads** would **decrease 700 to 1,200 aMW**.
- BPA would cut back on resource acquisitions by reducing CT purchases, but would still have **1,900 aMW firm surplus on a planning basis** due to lost loads, the addition of 380 aMW of renewables to support the "Green" Firm Power product, and BPA's renewable resource acquisition policy goals.

- A surplus would serve approximately 900 aMW of “in-lieu” loads of utilities that participate in the residential exchange program.
- Generation impacts would be lower with displacement of high-cost thermal resources.

The following modules are intrinsic to the BPA Influence alternative (section 2.3 describes each module):

RD-1	Seasonal Rates - Three Periods
RD-4	Eliminate Irrigation Discount
RD-7	Resource-Based Tier 1
DSI-2	Firm Service in Spring Only
CR-1	Fully Funded Conservation
CR-2	Renewables Incentives
CR-3	Maximize Renewables Acquisition
CR-4	“Green” Firm Power

Rates

BPA’s three-period seasonal rates would reflect hydro availability. Rates may be tiered, and the Tier 1 size would be based on a fixed percentage of Federal Base System firm capability, calculated on a monthly basis to reflect streamflows. A “Green” Firm Power rate would be offered to customers who would like acquire power served by renewable resources, the rate reflecting the cost of developing such resources. The irrigation discount (a rate discount to utilities for farmers who use electricity for irrigation or drainage) would be eliminated. Conservation spending would make BPA’s revenue requirements higher than all other alternatives except Status Quo. This alternative has the second-highest average rates (30 to 34 mills/kWh in nominal dollars).

Loads

Compared to Status Quo, BPA’s **utility loads** would **increase by 800 aMW** (table 4.4-10) primarily because of lower average rates; however, compared to 1995 Rate Case assumptions (table 4.4-9), BPA utility loads would be reduced approximately 600 aMW. BPA’s total firm and nonfirm **DSI loads** would **decrease** from Status Quo by **700 aMW** (about two-thirds of current DSI load), primarily because BPA would provide firm service in spring only, and DSIs would turn to other sources of firm service (table 4.4-10). Compared to Status Quo, BPA’s **total firm loads** would **decrease** by approximately an additional **400 aMW** by 2002, primarily because of price-induced conservation, fuel-switching, and changes in DSI firm service conditions.

Cost/Revenue Balance

Given its high rates and relatively lower loads, this alternative is least likely, after Status Quo, to achieve cost-revenue balance.

Resource Development

BPA would use market mechanisms to promote compliance with the Council Plan:

- contracts would be written so that BPA and its customers shared the costs and risks of meeting regional planning objectives; and
- rate levels would be driven by funding needs for BPA actions.

BPA would revise its plans to build the resources described in the 1992 Resource Program, eliminating some planned resources to adjust to the reductions in loads. BPA would adopt a policy goal of maximizing the acquisition of conservation and renewables to meet load. Because utilities would pick up some of the 660 aMW of conservation BPA had planned to acquire, and because BPA would offer DSM products and services, virtually all of the expected conservation would be obtained by 2002.

Table 4.4-2: New Resource Acquisitions: BPA Influence

BPA New Resource Acquisitions - 2002	
Resource Types	**aMW**
Conservation*	600
Efficiency Improvements	50
Renewables	380
Cogeneration	100
Power Purchases	0
Combustion Turbines	130
Coal	0
Total**	**1,250**

REST OF REGION New Resource Acquisitions - 2002	
Resource Types	**aMW**
Conservation	690
Efficiency Improvements	80
Renewables	100
Cogeneration	0
Power Purchases	0
Combustion Turbines	1,660
Coal	0
Total	**2,520**

*Includes 49 aMW of conservation due to codes and standards already in place.

**Rounding affects total.

This alternative involves the second-greatest regional resource acquisition and therefore is the most capital-intensive and risky in the face of uncertainty in resource technology, electricity price, and end-use demand. BPA would be using capital resources that the region might use for other developments with greater economic benefits. Structurally, under this alternative, a few decisionmakers would be making major resource decisions, continuing the historical pattern of PNW energy planning that developed the Federal system, the Canadian Treaty, the Southern Intertie, and the Hydro-Thermal Power Program. This planning paradigm is the "one-utility concept," which has been the planning concept for the development of the present regional wholesale power system.

Resource Operations

In this alternative, the regional load in 2002 would be 21,700 aMW, with resources totaling 23,600 aMW; nearly all of the surplus would be Federal. Eight hundred aMW of DSI load would be served by interruptible power. This alternative would reduce coal operations approximately 100 aMW and new CT operations by approximately 200 aMW from Status Quo (table 4.4-15).

Transmission System Development, Operation, and Rates

Under this alternative, BPA would continue to develop transmission on the basis of long-term, one-utility planning, with a high level of reliability. The major difference between this and the Status Quo alternative is that BPA would provide priority access and rate discounts to utilities that comply with the Council Plan and Program. As described in section 4.2.1.6 under the issue "Unbundling of Transmission and Wheeling Services," a few customers that would not qualify for priority access and/or rate discounts might try to find transmission services from other sources, build their own transmission, and/or build local generation. The overall effect might be a slightly smaller role for BPA in regional transmission system development than in the Status Quo (but probably more than in other alternatives). Table 4.4-16 shows that BPA's 500-kV transmission in 2002 is assumed to drop by approximately 10 percent to reflect this slight decrease in BPA's role; total regional 500-kV transmission is predicted to decrease only about 5 percent. This marginal decrease in transmission might be accompanied by a minor increase in local generation; however, it is also possible that the existing transmission system might simply be operated closer to full capacity instead.

Consumer Behavior

Retail rate effects for a particular utility depend on the ratio of BPA-purchased power costs to total costs and the total kWh sales for the utility. Assuming that BPA's rates for this alternative have decreased by 2 mills/kWh (about 6 percent) from Status Quo, then the decrease in the average cost of power for the typical consumer would be:

- Full requirements customer: approximately 2 mills/kWh (about 3.5 percent)
- Partial requirements customer: approximately 0.5-mill/kWh (about 1.5 percent)

Price-induced conservation and fuel switching would be minor (close to zero) compared to Status Quo in this alternative because utility customers of BPA would take load off BPA in order to prevent their rates from rising significantly.

Environmental Impacts

Under this alternative, regional resource development would be only slightly less than under Status Quo. Overall, the regional impacts associated with new generation and transmission resource development also would be slightly less. As shown in table 4.4-15, the operations of new CTs would be approximately 20 percent lower than in Status Quo and operations of existing coal would be about 3 percent less, but operations of existing, older CTs would be approximately the same. However, the higher amount of renewable resources in this alternative would lead to greater land use impacts than all other alternatives (approximately 7 percent more). Overall, total environmental impacts (table 4.4-20) are generally comparable to the Status Quo alternative, and environmental externalities would be only about 3 percent lower than Status Quo.

4.4.2.3 Proposed Action - Market-Driven BPA

Features of this alternative include:

- Program costs are cut for conservation, administration and transmission system development, leading to lower BPA rates.
- **Average PF** rate in 2002 is about **29 to 33 mills**/kWh (nominal $). When implemented in the long term, **Tier 1** would sell for about **27 to 33 mills**/kWh, with **Tier 2** at about **36 to 40 mills**/kWh in nominal $.
- Compared to Status Quo, BPA's **utility loads increase approximately 1,400 aMW**.
- BPA's **DSI firm loads** actually **increase by 600 aMW in the short term, but decline over time.**
- BPA cuts back on resource acquisitions by reducing CT purchases and planned power purchases (200 aMW) and expects some 100 aMW of conservation formerly under BPA programs to come from independent utility programs. These changes eliminate the firm surplus shown in Status Quo.
- Generation impacts are higher because existing high-cost thermal resources are displaced less.

The following modules are intrinsic to the Market-Driven BPA alternative (section 2.3 describes each module):

FW-2 BPA Proposed Fish and Wildlife Reinvention

RD-1 Seasonal Rates - Three Periods

RD-4 Eliminate Irrigation Discount

RD-6 Load-Based Tier 1

DSI-3 Declining Firm Service

CR-4 "Green" Firm Power

Rates

This alternative assumes decreased BPA conservation expenses (with no change in energy savings achieved), decreased BPA transmission investments and replacements, and additional market revenues from products to keep the PF rate constant in nominal terms through 1999 and rising with inflation thereafter. BPA would offer a "Green" Firm Power product to those utilities that desire it (but because this product covers its own costs, it would be revenue-neutral to BPA). This alternative also assumes that, in the long term, BPA would develop a tiered rate design, with a Tier 1 size based on a percentage of historical loads for each customer and a percentage of the existing capability of FBS resources. Federal system capability serving Tier 1 loads would be fixed (purchased power would make up any gap). The Tier 2 price would equal the estimated BPA marginal cost for each year. In the long term, tiered rates would stimulate price-induced fuel-switching and conservation independent of BPA programs.

In the short term, BPA probably would not implement a tiered rates proposal, for three reasons:

- the costs of new power have dropped so rapidly that there would be no substantial difference between average costs of power and marginal costs;
- customers are moving to develop conservation programs themselves, even without a BPA tiered-rate signal; and
- under current market conditions, tiered rates appear to be a disincentive to doing business with BPA and at odds with the orientation of this alternative, which is customer-focused.

This alternative, Maximum Financial Returns, and Short-Term Marketing project the lowest rate trends for the study period except for the Minimal BPA alternative (see table 4.4-7), due to the decreases in conservation spending, overhead expenses and the cuts in transmission investments. The sale of unbundled and rebundled products is expected to produce substantial revenues that would be credited back to lower wholesale power rates.

Loads

Compared to Status Quo, under the Market-Driven alternative, BPA would gain 1,400 aMW of utility loads, primarily by keeping average and marginal (Tier 2) rates low enough to prevent many utility customers from turning to other power sources. Due to lower rates, BPA would regain, **in the short term,** a total of almost 600 aMW of DSI loads lost in the Status Quo alternative to other power sources. **In the long term,** however, public agency and DSI firm loads are assumed to decrease somewhat from year to year in response to the Tier 2 rate and DSI contract terms.

Cost/Revenue Balance

Overall, this alternative would be more likely than Status Quo to maintain BPA's cost/revenue balance because cost containment and the development of products and services that respond to customer needs would help reduce rate increases and retain load.

Resource Development

This alternative assumes that:

- costs and risks would be shared only with full requirements customers under long-term contracts;
- flexible short- and long-term arrangements would be offered; and
- unbundled products would be competitively priced.

BPA would not acquire the additional generation proposed by the 1992 Resource Program other than resources already committed to, but would rely on short-term purchases to fill in any deficits.

BPA direct conservation acquisition would be reduced, but independent conservation programs carried out by customers would make up the difference, so that conservation targets for BPA loads would continue to be achieved. BPA would acquire renewable resources to support sales of “green” power to utilities that pay for that product’s additional cost. Other BPA resource acquisitions would be the same as for the BPA Influence alternative. Because BPA loads would be higher, there would be little if any surplus. Any in-lieu power deliveries under the Residential Exchange would be based on spot market power purchases. Regional resource development would be less than under the Status Quo or BPA Influence alternatives because fewer new CTs would be developed to serve loads shifted away from BPA. If market competition and low gas prices continued to put downward pressure on the market price for power, existing baseload resources, such as WNP-2, would become increasingly uneconomic, and could be shut down. It is likely that additional power purchases would replace any such terminated baseload resources.

Under this alternative, numerous decisionmakers are choosing energy purchases or resource developments. Efficiency may be reduced if the individual decisions are not coordinated, but errors arising from incomplete information or changing conditions would tend to be smaller, and the consequences less than would result from misdirection of a comprehensive regional plan.

Table 4.4-3: New Resource Acquisitions: Market-Driven BPA (Proposed Action)

BPA New Resource Acquisitions - 2002		REST OF REGION New Resource Acquisitions - 2002	
Resource Types	**aMW**	**Resource Types**	**aMW**
Conservation*	460	Conservation	800
Efficiency Improvements	50	Efficiency Improvements	80
Renewables	80	Renewables	100
Cogeneration	100	Cogeneration	0
Planned Purchases	190	Planned Purchases	0
Combustion Turbines	130	Combustion Turbines	690
Coal	0	Coal	0
Total**	**1,000**	**Total**	**1,660**

*Includes 49 aMW of conservation due to codes and standards already in place.

**Rounding affects total.

Resource Operations

The regional loads and resources would each be approximately 22,500 aMW in 2002, with no regional or BPA surplus. This alternative incorporates new DSI firm contracts that would not incorporate a quartile structure, and there is, therefore, no top quartile service in this alternative. Compared to the Status Quo alternative, this alternative has less than half the operations of new CTs; however, existing higher-cost thermal resources (coal and older CTs) operate somewhat more than in Status Quo (table 4.4-15). BPA would analyze all planned and existing generation projects and consider terminating those that are more expensive than firm power purchases or new resources.

Transmission System Development, Operation, and Rates

BPA could continue in its role as the main provider of regional transmission facilities. The major difference between this and the Status Quo alternative is that, after BPA reviews its reliability criteria with its customers, it is likely that BPA's transmission system would evolve over the long term toward a lower-cost, somewhat lower-reliability system. In addition, unbundling transmission services and pricing transmission using more distance-based rates and opportunity and incremental pricing, to the extent adopted, would lead to clearer price signals that might lead to more efficient transmission development. Making wheeling contracts assignable might mean that the existing transmission system would be used more efficiently and that less new transmission would be needed.

If BPA's customers want BPA to reduce overall transmission costs by planning toward a somewhat less stringent reliability standard, BPA would construct less new transmission capacity, and operate the existing capacity at higher load factors (i.e., closer to "full capacity"). New facilities would be constructed as needed to serve Federal loads, to respond to FERC-ordered transmission service (where existing capacity is fully utilized), and where the costs of adding new capacity can be recovered by wheeling revenues for the facility in question. System outage frequencies could increase somewhat, as transmission facilities would be constructed and operated with lower "reserves." Transmission pricing signals could lead to more local generation and some degree of increased transmission development by utilities other than BPA. Although it is difficult to identify the specific projects BPA might postpone or avoid, for the purposes of analysis, table 4.4-16 shows a 10-percent drop in BPA construction of new 500-kV transmission in 2002; total regional 500-kV transmission is predicted to decrease only about 5 percent. BPA's 230-kV transmission development might decrease to a greater extent; for example, projects such as the 22-km (13.7-mi) St. Clair-Olympia project or 40-km (25-mi) Snoking-Maple Valley lines might be constructed by other utilities and/or avoided (at the cost of decreased reliability). Table 4.4-16 shows BPA would reduce 230-kV transmission development by approximately 50 percent, while 230-kV development by other utilities would increase by approximately 20 percent compared to Status Quo. Overall, however, regional 230-kV development would be only slightly less than in Status Quo.

Consumer Behavior

Retail rate effects for a particular utility depend on the ratio of BPA-purchased power costs to total costs and the total kWh sales for the utility. Assuming that BPA's rates for this alternative are approximately 3 mills/kWh (about 9 percent) lower than for Status Quo, then the decrease in the average cost of power for a typical consumer would be:

- Full requirements customer: approximately 3 mills/kWh (about 5 percent)
- Partial requirements customer: approximately 1 mill/kWh (about 2 percent)

Price-induced conservation and fuel switching would be minor (close to zero) compared to Status Quo in this alternative because BPA's rate would be close to the market price for power.

Environmental Impacts

BPA and the region acquire only about two-thirds the amount of new resources acquired in Status Quo. Most impacts associated with new regional resource development are lower than in Status Quo (table 4.4-19). Impacts associated with the operation of existing coal, CTs, extraregional sales, and power purchases are somewhat higher than in Status Quo, in part because more existing coal generation operates. Environmental externality costs associated with air emissions of new and existing thermal generation are approximately 4 percent higher than in Status Quo (table 4.4-20), primarily because of higher amounts of coal operations. Electricity rates are lower than in Status Quo for public and private utility customers; however, the overall slight boost to the regional economy is not large enough to cause statistically significant growth in employment.

4.4.2.4 Maximize BPA's Financial Returns

For the Maximize Financial Returns alternative, BPA would cut costs without implementing tiered rates, resulting in increased revenues.

Features of this alternative include:

- Program costs would be cut for conservation, generation and transmission system development, leading to lower rates than Status Quo.
- **Average PF** rate in 2002 would be about **29 to 33 mills**/kWh (nominal $), allowing BPA a 10 percent return over cost. Rates would be capped at the maximum sustainable revenue point.
- BPA's **utility loads would increase** by about **1,400 aMW** compared to the Status Quo alternative, due to **consumer responses to lower rates**.
- BPA's **DSI loads would increase by about 600 aMW** due to price changes.
- With a potential firm surplus eliminated, BPA would plan almost **500 aMW of power purchases** to meet loads. About 100 aMW of conservation formerly under BPA programs would come from independent utility programs.
- Higher loads would increase thermal generation and impacts, from both high-cost older generators and lower-cost new generators.

The following modules are intrinsic to the Maximize Financial Returns alternative (modules are described in section 2.3):

FW-3 Lump-Sum Transfer

RD-4 Eliminate Irrigation Discount

DSI-5 100% Firm Service

CR-4 "Green" Firm Power

Rates

Consistent with the principles of this alternative, BPA would set its rates close to, but not above, the maximum sustainable revenue level. This would lead to rates that would be comparable to those in the Market-Driven BPA alternative.

Loads

Under the Maximize Financial Returns alternative, BPA would retain approximately 1,400 aMW of utility loads lost to other power sources in Status Quo because BPA prices would be preferable to non-BPA generation. Compared to Status Quo, BPA would gain almost 600 aMW of DSI loads. Overall, BPA total firm loads would be 1,400 aMW higher than under Status Quo (approximately the same as in Market-Driven BPA). There would be no DSI top quartile service in this alternative, because it is assumed that the contracts offered under this alternative would not include a top quartile service provision.

Cost/Revenue Balance

This alternative would be more likely than any other except Minimal BPA to achieve cost/revenue balance because BPA would cut program costs as necessary to retain loads.

Resource Development

BPA would acquire new generation in the form of almost 500 aMW of power purchases, but would terminate conservation contracts that were not self-supporting. Any additional conservation BPA developed would result from new DSM efforts undertaken as part of marketing activities.

Conservation acquisition would be less than in all alternatives except Minimal BPA, and power purchases would be higher than in all other alternatives. Because BPA would retain most of its load, competitors would build fewer new CTs to serve load moving away from BPA service. However, as in Market-Driven BPA, if market competition and low gas prices continued to put downward pressure on the market price for power, existing baseload resources, such as WNP-2, would become increasingly uneconomic, and could be shut down. It is likely that additional power purchases would replace any such terminated baseload resources.

Under the Maximum Financial Returns alternative, as under the Market-Driven alternative, numerous decisionmakers are choosing energy purchases or resource developments. Efficiency may be reduced if the individual decisions are not coordinated, but errors arising from incomplete information or changing conditions would tend to be smaller, and the consequences less than would result from misdirection of a comprehensive regional plan.

Resource Operations

In this alternative, the regional load in 2002 would be 22,500 aMW, with both the Federal and total regional systems in load/resource balance. Compared to the Status Quo alternative, this alternative shows substantially more operation by existing coal and CT generation, in part because fewer new CTs would be acquired regionally than in any other alternative (see tables 4.4-13 and 4.4-15 in section 4.4.3). BPA would analyze all planned and existing generation projects and consider terminating those that are more expensive than firm power purchases or new resources.

Table 4.4-4: New Resource Acquisitions: Maximize Financial Returns

BPA New Resource Acquisitions - 2002	
Resource Types	**aMW**
Conservation*	260
Efficiency Improvements	50
Renewables	80
Cogeneration	100
Planned Purchases	470
Combustion Turbines	130
Coal	0
Total	**1,070**

REST OF REGION New Resource Acquisitions - 2002	
Resource Types	**aMW**
Conservation	800
Efficiency Improvements	80
Renewables	100
Cogeneration	0
Planned Purchases	0
Combustion Turbines	560
Coal	0
Total	**1,520**

*Includes 49 aMW of conservation due to codes and standards already in place.

Transmission System Development, Operation, and Rates

BPA's transmission system planning and development would focus on maximizing returns from each component of the transmission system. BPA's statutes may limit BPA from receiving significant "profits" from specific transmission investments; however, BPA might construct new transmission facilities to access new markets for power sales or sources of power. For example, it might participate in the development of new transmission links to the inland Southwest in order to make sales and exchanges to that region, or it might construct additional transmission capacity to access gas supplies in Alberta (if it could not gain access to the same markets through FERC-ordered transmission service on other utilities' facilities). BPA might also sell existing facilities for which revenues do not cover the costs of operations, maintenance, and repair. Transmission of Federal power would be sold separately from the power itself, and the range of costs of transmitting Federal power to different parts of the BPA system would be reflected in the range of costs paid by customer utilities.

Although BPA might construct new transmission lines to access strategic markets (included in the total of BPA 500-kV transmission development in table 4.4-16 is at least one such project, a 200-km (124-mi) line), overall, BPA's share of regional transmission development (particularly 200-kV and below) would probably fall. As indicated in table 4.4-16, it is assumed that BPA and regional 500-kV transmission development would be only slightly less than in Status Quo in 2002; however, BPA 230-kV transmission development would be only 10 percent of the amount projected for Status Quo. Other utilities' 230-kV transmission development would increase 50 percent as they incrementally added 230-kV facilities to replace the regional 500-kV transmission not constructed by BPA. Additional local generation facilities (e.g., cogeneration or CTs) might be developed in response to the net reduction in 230-kV transmission development.

Consumer Behavior

Retail rate effects for a particular utility depend on the ratio of BPA-purchased power costs to total costs and the total kWh sales for the utility. Assuming that BPA's rates for this alternative are approximately 3 mills/kWh (about 9 percent) lower than for Status Quo, then the decrease in the average cost of power for the typical consumer would be the same as for Market-Driven:

- Full requirements customer: approximately 3 mills/kWh (about 5 percent)
- Partial requirements customer: approximately 1 mill/kWh (about 2 percent)

In 2002, price-induced fuel switching *to* electricity would increase from the Status Quo alternative by approximately 100 aMW, reflecting the relatively low average PF rate and lack of tiered rates in this alternative.

Residential exchange loads of IOUs would decrease by approximately 200 aMW.

Environmental Impacts

In this alternative, BPA would acquire fewer new resources than under the Status Quo, and would rely more on power purchases to serve load (table 4.4-11). Other utilities also would acquire fewer new resources, and as a result, regional new resource acquisitions and associated land use, air, and water impacts would be less than under the other alternatives (table 4.4-13 and 4.4-19). However, land use associated with new transmission development would be greater than in all other alternatives, in part because BPA would build intertie lines where financially attractive, and would construct less transmission for regional needs. Other utilities would build transmission instead of BPA, but would do so at lower voltages (requiring more miles of transmission right-of-way to serve loads) (table 4.4-16).

Air and water impacts from the operation of existing coal and CTs, and from power purchases (assumed to be thermal generation such as CTs) would be higher than under Status Quo. Because this alternative involves a high level of power purchases, it is likely that much of the thermal generation impacts would occur outside the region (e.g., the Pacific Southwest). The primary influence on air quality impacts would be the high existing coal operations in this alternative (higher than all others). As a result, environmental externality estimates for air quality impacts of this alternative would be higher than any other alternative except Minimal BPA (see table 4.4-20). On a regional basis, electric rates would be slightly lower, but this does not translate into significant changes in employment growth.

4.4.2.5 Minimal BPA Marketing

In the Minimal BPA alternative, BPA would cut costs and eliminate all resource acquisitions recommended in the 1992 Resource Program, including conservation, that are not already under construction.

Features of this alternative include:

- Program costs would be cut for new conservation and transmission system development.
- **Average PF** rate in 2002 would be about **28 to 32 mills**/kWh (nominal $).
- BPA's **utility loads would increase** by about **1,600 aMW**, compared to Status Quo.
- BPA's **total DSI loads** would be approximately the same as in Status Quo. DSI top quartile service would not be offered under this alternative.
- BPA would drop most CT acquisitions and all other resource acquisitions except for small amounts of resources already under construction. About 130 aMW of conservation formerly under BPA programs would come from independent utility programs. **BPA would be in load-resource balance**.
- Higher loads would increase thermal generation and impacts, from both high-cost older generators and lower-cost new generators. Total thermal operations would be higher than under all other alternatives.

The following modules are intrinsic to the Minimal BPA alternative (modules are described in 2.3):

FW-3 Lump-Sum Transfer

DSI-3 Declining Firm Service

Rates

Without the added cost of new resource acquisitions and transmission construction after 1996, BPA's rates would remain low, but the limited supply of BPA power would force customers to acquire resources to serve their load growth. This alternative projects an average PF rate lower than all other alternatives (in the range of 28 to 32 mills/kWh in nominal dollars). Although costs would be reduced substantially, no additional revenue from the market-based sale of bundled or unbundled products would be available.

Loads

BPA's utility loads would increase by about 1,700 aMW, compared to Status Quo, because utilities would not turn as much to other sources of power and because lower rates would cause "reverse fuel switching" (that is, switching from gas to electricity). Under the Minimal BPA alternative, BPA would retain the firm utility loads lost in the Status Quo alternative, and DSI total loads on BPA would be approximately the same as in Status Quo.

Cost/Revenue Balance

Because BPA could sell all of its limited supply of firm power due to its relatively low cost, there would be no BPA firm surplus, and costs and revenues would balance.

Resource Development

BPA would terminate or buy out any obligations to acquire further conservation, renewables, or cogeneration, as shown in table 4.4-5. Because BPA would sell all of its limited supply of firm power, there would be no BPA firm surplus. The rest of the region would develop resources at market prices, almost exclusively CTs, but also some conservation, to serve load growth. DSIs would have to buy power from other suppliers to replace BPA power as utilities exercised their preference rights to BPA power. The resource development role would be assumed by other regional utilities and IPPs. With the large number of decisionmakers involved, this alternative could lead to the greatest regional acquisition of CTs of all the alternatives except Status Quo and BPA Influence. If BPA terminated any existing resources, there would not be any BPA acquisitions to replace lost output, and development or power purchases by the rest of the region would have to increase to meet the total regional demand.

Table 4.4-5: New Resource Acquisitions: Minimal BPA

BPA New Resource Acquisitions - 2002	
Resource Types	**aMW**
Conservation*	130
Efficiency Improvements	50
Renewables	0
Cogeneration	100
Planned Purchases	0
Combustion Turbines	130
Coal	0
Total**	**400**

REST OF REGION New Resource Acquisitions - 2002	
Resource Types	**aMW**
Conservation	800
Efficiency Improvements	80
Renewables	100
Cogeneration	0
Planned Purchases	0
Combustion Turbines	1,530
Coal	0
Total**	**2,500**

*Includes 49 aMW of conservation due to codes and standards already in place.

**Rounding affects total.

Resource Operations

Under this alternative, the regional load in 2002 would be 22,800 aMW, with both the smaller Federal system and the regional system in load/resource balance. With the Federal system not growing, there would be more CT construction by others; this alternative would result in the largest new CT generation development among the alternatives except Status Quo and BPA Influence—approximately 1,700 aMW. The operation of existing coal and CT resources would also be high, and overall, thermal operations would be higher than in all other alternatives.

Transmission System Development, Operation, and Rates

In this alternative BPA would continue to maintain and replace existing transmission facilities, but would construct few new facilities. Although under EPA-92 FERC could order BPA to construct transmission capacity for a party requesting such service, it is assumed here that BPA would avoid significant new construction.

Existing loads would be served under existing transmission rates schedules. Load growth would be served by utilities other than BPA, and new transmission capacity to serve new load and to integrate generating resources would be constructed by other utilities. Although BPA (which currently owns three-quarters of the region's transmission capacity) would continue to play an important role in transmission system operations, over time the responsibility for maintaining the reliability of the transmission system by adding new capacity would devolve toward other utilities. To the extent that RTGs provide a forum for transmission system planning to replace BPA's current role, transmission planning might continue to have a long-term focus; however, it is likely that the balance between cost and reliability might shift somewhat in the direction of lower cost. Other utilities would take on larger transmission development roles; however, the overall growth in regional transmission capacity would probably be less than under the Status Quo alternative. BPA would construct new 500-kV transmission only where necessary to relieve existing transmission reliability problems or transmission constraints. It is assumed, as shown in table 4.4-16, that in 2002, BPA's share of 500-kV transmission would shrink to less than half that of Status Quo, and its share of 230-kV transmission to only 5 percent of the amount under Status Quo. On the other hand, the amount of 230-kV transmission by other utilities would increase by 75 percent compared with Status Quo, as they incrementally added 230-kV facilities to replace the 500-kV transmission not constructed by BPA. Overall, regional 500-kV transmission would drop by 25 percent, and 230-kV transmission development would increase by approximately 10 percent. In the long-term (post-2002), significant increases in 230-kV transmission could be predicted, because as loads and resources in the region grow, it would require more kilometers of 230-kV transmission to accommodate that growth than if 500-kV transmission were constructed.

Consumer Behavior

Retail rate effects for a particular utility depend on the ratio of BPA-purchased power costs to total costs and total kWh sales for the utility. Assuming that BPA's rates for this alternative are approximately 4 mills/kWh (about 12 percent) lower than Status Quo, then the decrease in average cost of power for the typical consumer would be:

- Full requirements customer: approximately 4 mills/kWh (about 7 percent)
- Partial requirements customer: approximately 1 mill/kWh (about 3.6 percent)

In 2002, price-induced fuel switching *to* electricity would increase from the Status Quo alternative by approximately 100 aMW, reflecting the relatively low average PF rate and lack of a tiered rate structure in this alternative.

Residential exchange loads of IOUs would increase by 100 aMW in response to the relatively lower rate for PF power exchanged compared to the Status Quo.

Environmental Impacts

Under this alternative, BPA would acquire few new generating resources or transmission facilities (tables 4.4-5 and 4.4-16). In BPA's place, other utilities would acquire new resources, particularly CTs. Air, land, and water impacts associated with new resource development and operation would be higher than in all other alternatives except Status Quo and BPA Influence. Overall, the operation of existing and new thermal resources would be higher than all other alternatives. As a consequence, environmental externality estimates for air quality impacts of this alternative are higher than all other alternatives (table 4.4-20) but still would be only about 13 percent higher than Status Quo. Regional electric rates would be slightly lower than under Status Quo, but the positive effect on the economy would not be sufficient to cause any statistically significant difference in regional employment growth rates.

4.4.2.6 Short-Term Marketing

Features of this alternative include:

- Program costs are cut for new conservation and resource acquisitions and new transmission system development, unless cost-effective in 5 years or less.
- **Average PF** rate in 2002 would be **29 to 33 mills**/kWh (nominal $). Tier 1 would be priced at 27 to 31 mills/kWh; Tier 2 would be 36 to 40 mills/kWh (nominal $).
- BPA's **utility loads** would increase approximately **1,400 aMW** compared to Status Quo. BPA would use 300 aMW of surplus to serve "in-lieu" loads of utilities participating in the residential exchange program.
- BPA's **DSI total loads** would be approximately the same as under Status Quo, with 800 aMW lost to other power sources compared to the 1995 Rate Case assumptions.
- BPA would drop most renewables acquisitions. About 130 aMW of conservation formerly under BPA programs would come from independent utility programs. BPA would be in **load-resource balance** after serving approximately 300 aMW of in-lieu loads.
- Higher loads and lower resource acquisitions than most other alternatives would lead to increased thermal generation and impacts from existing coal and CT resources.

The following modules are intrinsic to the Short-Term Marketing alternative (modules are described in section 2.3):

FW-2	BPA Proposed Fish and Wildlife Reinvention
RD-4	Eliminate Irrigation Discount
RD-8	Market-Based Tier 2
DSI-3	Declining Firm Service

Rates

Without the added costs of new resource acquisitions and transmission construction, BPA's rates would remain low, but the limitation on BPA power to short-term sales would cause the generating customers to obtain their own supplies. BPA's average PF rate would be lower than under Status Quo, and about the same as under the Market-Driven alternative.

Loads

Under the Short-Term Marketing alternative, as under the Maximize Financial Returns alternative, BPA would retain the forecasted 1995 Rate Case utility loads because utilities would continue to place load on BPA rather than turn to other sources, in large part due to lower rates. Utility loads on BPA would increase by 1,400 aMW compared with Status Quo; overall firm loads would be 1,000 aMW higher than Status Quo. There would be no top quartile service offered to DSIs in this alternative, but total DSI loads on BPA would be about the same as under Status Quo. After 2001, it is assumed that BPA's traditional public agency load would increasingly be served by new public utility generation (CTs), based on a desire for long-term service as the perceived risks of BPA cost increases. This shift in public agency loads to CTs would leave BPA with surplus firm power which it would use to serve approximately 300 aMW of "in-lieu" loads of IOUs participating in the residential exchange program.

Cost/Revenue Balance

While BPA's costs would be the same as the Market-Driven BPA alternative, the limitation on sales to a 5-year maximum term might make it more difficult for BPA to recover its costs and thus maintain stable rates in the long term.

Resource Development

BPA would function primarily as a broker, making long-term acquisitions only if they were economically justified in support of short-term marketing.

- Prices of unbundled products and transmission would be based on cost and market competitiveness.
- Transmission would be planned and constructed to enhance marketing opportunities.

Table 4.4.-6 shows resource acquisitions in this alternative.

Table 4.4-6: New Resource Acquisitions: Short-Term Marketing

BPA New Resource Acquisitions - 2002	
Resource Types	**aMW**
Conservation*	350
Efficiency Improvements	50
Renewables	0
Cogeneration	100
Planned Purchases	80
Combustion Turbines	130
Coal	0
Total**	**700**

REST OF REGION New Resource Acquisitions - 2002	
Resource Types	**aMW**
Conservation	800
Efficiency Improvements	80
Renewables	100
Cogeneration	0
Planned Purchases	0
Combustion Turbines	940
Coal	0
Total	**1,910**

*Includes a 49 aMW of conservation due to codes and standards already in place.
**Rounding affects totals.

The Short-Term Marketing alternative, like the Market-Driven alternative, has numerous decisionmakers involved in development of the regional power system, with the same effects as under the Maximize Financial Returns alternative.

Resource Operations

In this alternative, the regional load in 2002 would be 22,500 aMW, with both the Federal and regional systems in load/resource balance. The profile of resource operations is very similar to that in Maximize Financial Returns. New CT operations would be slightly lower than under the Minimal BPA alternative (approximately 500 aMW) (see table 4.4-5).

Transmission System Development, Operation, and Rates

BPA would phase out long-term contracts and market new power and transmission services only on a short-term basis (less than 5 years), to the extent that doing so is consistent with EPA-92. BPA would have almost no incentive to construct new transmission, unless it were offered long-term no-risk contracts to construct specific new facilities. The effects on transmission system development would probably be similar to those of the Minimal BPA Marketing alternative; i.e., less BPA and more non-BPA transmission development in the short term, and more localized generation (e.g., CTs and cogeneration).

Consumer Behavior

Retail rate effects for a particular utility would depend on the ratio of BPA-purchased power costs to total costs and the total kWh sales for the utility. Assuming that BPA's rates for this alternative would be approximately 3 mills/kWh (about 9 percent) lower than for Status Quo, then the decrease in the average cost of power for the typical consumer would be the same as for Market-Driven:

- Full requirements customer: approximately 3 mills/kWh (about 5 percent)
- Partial requirements customers approximately 1 mill/kWh (about 2 percent)

In 2002, price-induced conservation and fuel switching would show minor changes (near zero) compared with the Status Quo alternative.

Residential exchange loads of IOUs would decrease by 100 aMW.

Environmental Impacts

In this alternative, BPA would acquire fewer conservation and generation resources than in Status Quo. The impacts to air and water from the operations of new and existing resources would be higher than under Status Quo, primarily because of increased operation of existing coal and CT resources (tables 4.4-15 and 4.4-19). Overall, the environmental externality estimates for air quality impacts of this alternative would be higher than all alternatives except Maximize Financial Returns and Minimal BPA (table 4.4-20). Although regional electric rates would be lower than under Status Quo, this effect would not be large enough to cause any statistically significant difference in regional employment growth rates.

4.4.3 Summary of Illustrative Results Under 1994-1998 Biological Opinion Hydro Operation

This section summarizes and provides the numerical documentation of the analysis presented in section 4.4.2. As pointed out at the beginning of that section, in the current electric utility climate, prices and conditions are changing so rapidly that numerical analysis cannot be considered definitive. However, BPA expects that the principles behind the analysis and the behavior of parties in this business remain constant, and that the numerical analysis serves to illustrate how those behaviors and relationships work.

Some basic analytical assumptions are the same for all of the alternatives, as follows:

- Inputs from the 1995 Rate Case assumptions remain constant:
    - √ Medium load forecasts
    - √ Generating resource costs
    - √ Fuel costs and availability
    - √ Regional generating resource supply curves
    - √ Resource Program acquisitions, except as noted.
- Pacific Northwest Coordination Agreement and Columbia River Treaty planning procedures and obligations remain unchanged.
- DSI loads served by BPA are different among alternatives, but it is assumed that aluminum prices and demand for DSI products are high enough that in the year 2002 a total of 2,700 aMW of DSI load would operate under all alternatives.
- Transmission access is consistent with the Energy Policy Act of 1992. The exception would be under Minimal BPA, in which BPA would attempt to be exempt from the requirement to construct new transmission.
- BPA organic statutes, including the Bonneville Project Act, the Federal Columbia River Transmission System Act, the Regional Preference Act, and the Northwest Power Act remain unchanged, except as noted.

4.4.3.1 Rates

Table 4.4-7 illustrates the nominal PF rate levels that might occur in each alternative in 2002 under the assumption of current hydro operations. For the BPA Influence, Market-Driven BPA, and Short-Term Marketing alternatives, in the long term, BPA would sell firm power under tiered rate structures, so the prices for the two tiers are shown below the average price (although for the Market-Driven BPA alternative, tiered rates might not be implemented in the short term).

Table 4.4-7: Average PF Rate in 2002 (mills/kWh; nominal $)
SOS: 1994 - 1998 Biological Opinion

Alternative	Status Quo	BPA Influence	Market-Driven	Maximize Financial Return	Minimal BPA	Short-Term Marketing
Average	32 - 36	30 - 34	29 - 33	29 - 33	28 - 32	29 - 33
Tier 1	N/A	29 - 33	27 - 31	N/A	N/A	27 - 31
Tier 2	N/A	36 - 40	36 - 40	N/A	N/A	36 - 40

The rate levels were the starting point for further evaluations of loads and market responses to alternatives. Typical responses by customer category are illustrated in figure 4.4-1. Initial rate estimates included adjustments to anticipate their cost and load effects.

Additional load losses not included in the rate projections would push BPA power rates higher, as would additional resource costs. That is, if market conditions or other factors cause BPA's customers to serve more of their loads from non-BPA suppliers than is estimated here, BPA's costs would be distributed over a smaller base of sales; rates would therefore have to be higher to provide the same amount of revenue. Similarly, even if BPA's loads are as assumed here, increases in resource costs would add to BPA's revenue requirement and result in increases in BPA's rates unless BPA developed additional revenue from other products separate from firm requirements power sales. *In either case, the practical limit on BPA's rate level is the maximum sustainable revenue level.*

The Status Quo alternative increases BPA power rates due to continuing expenditures at historical levels for energy conservation programs, resource acquisitions, transmission construction, and fish and wildlife enhancement. In the BPA Influence, Market-Driven, and Short-Term Marketing alternatives, the Tier 2 rate is set near the long-term cost of alternative resources. For all three tiered-rates alternatives, the Tier 1 rate increases as necessary to generate enough revenue to meet BPA's requirements.

Rates for the Minimal BPA alternative are lower, because of lower program spending and no resource acquisitions. Rates for the Maximize Financial Returns alternative are deliberately set at the maximum sustainable revenue level (approximately 30 to 32 mills in nominal dollars).

4.4.3.2 Loads

Loads for the EIS alternatives in 2002, under current river operations, are shown in table 4.4-8.

FIGURE 4.4-1

Market Responses of Customers to Increases in BPA's Rates for Products and Services

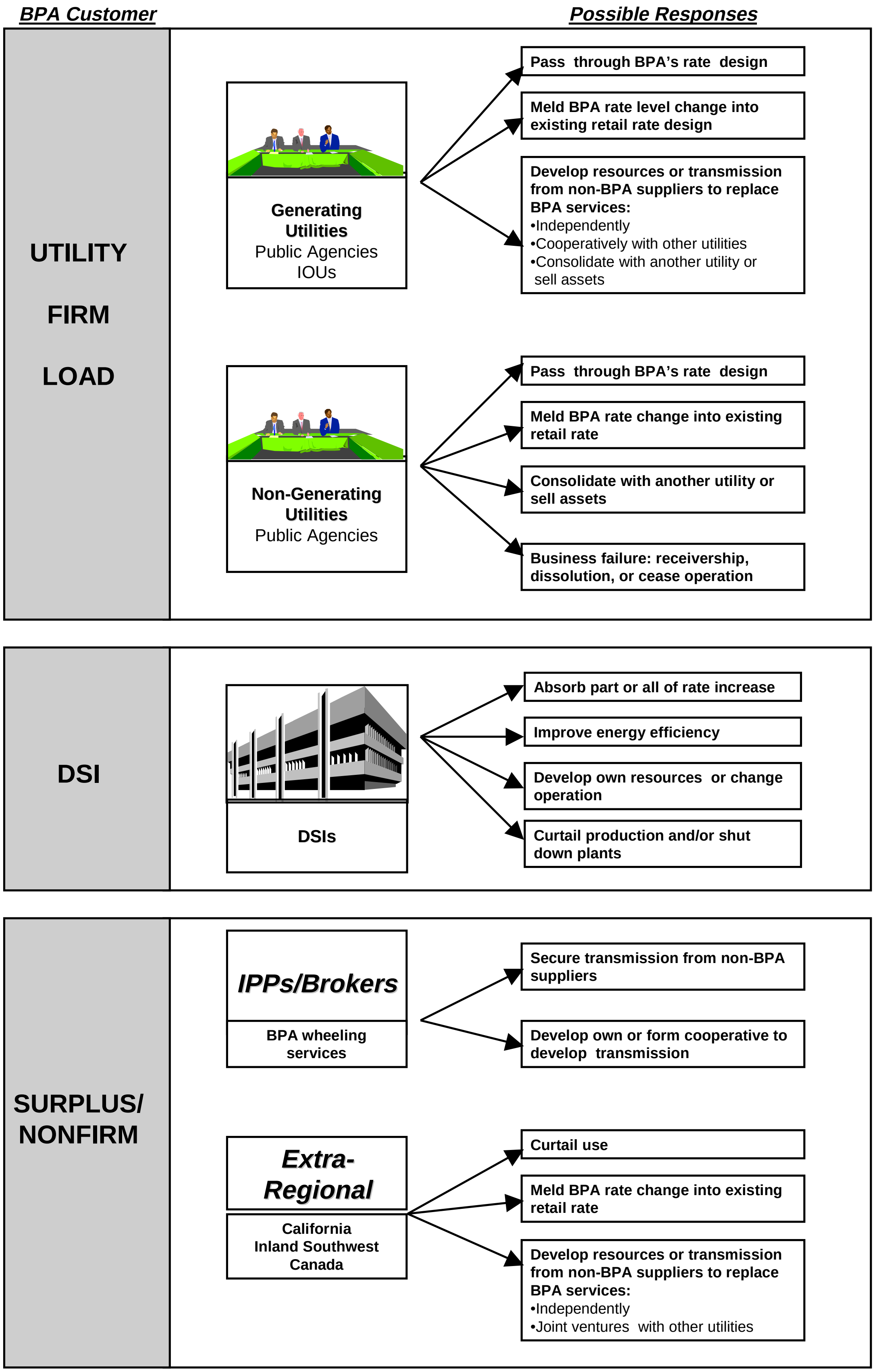


Table 4.4-8: Comparison of Loads and Resource Development by 2002 (aMW)

All numbers except Rate Case numbers and adjusted totals represent differences from 1995 Rate Case Forecast

			Rate Case	Status Quo	BPA Influence	Market Driven	Maximize Financial Returns	Minimal BPA	Short-Term Marketing
1	**BPA**	1995 Rate Case loads for 2002	9,000	9,000	9,000	9,000	9,000	9,000	9,000
2		Price-induced conservation		0	0	0	0	0	0
3		Fuel switching		0	0	0	100	100	0
4		Change in DSI load forecast from RC			200	200	200	200	200
5		DSI Load from RC served as interruptible			-800	0	0	0	0
6		Utility self-generation		-1,400	-600	0	-100	200	0
7		DSI self-generation (for firm load)		-800	-1,500	-200	-200	-800	-800
8		Residential exchange in-lieu load		900	900	0	0	0	300
9		Load obligation transfer (re BPA conserv.)			0	-100	-100	-500	-100
10		Adjusted BPA load	9,000	7,600	7,200	8,900	9,000	8,300	8,600
11									
12		1995 Rate Case interruptible load	0	0	0	0	0	0	0
13		Change in interruptible load		300	800	0	0	0	0
15		Adjusted BPA interruptible load	0	300	800	0	0	0	0
16									
17		1995 Rate Case resources for 2002	8,700	8,700	8,700	8,700	8,700	8,700	8,700
18		Conservation		600	600	500	300	100	300
19		Combustion turbines		300	100	100	100	100	100
20		Other (effic., renewables, co-gen)		200	500	200	200	100	100
21		Power purchases		200	0	200	500	0	100
22		Conservation already deducted from RC			-500	-500	-500	-500	-500
23		Gen. resources already deducted from RC			-300	-300	-300	-300	-300
24		Adjusted BPA resources	8,700	9,200	9,000	8,900	9,000	8,400	8,600
25									
26		Adj. BPA firm load/resource balance (resources - loads)	-300	1,600	1,900	0	0	0	0
27									
28	**Rest of Region**	1995 Rate Case load for 2002	13,300	13,300	13,300	13,300	13,300	13,300	13,300
29		Load increase from utility & DSI self-gen			2,100	200	300	600	800
30		Load inc. from DSI self-gen for non-firm			0	0	0	0	0
31		Residential exchange		0	0	0	-200	100	-100
32		Residential exchange in-lieu load		-900	-900	0	0	0	-300
33		Load obligation transfer (re BPA conserv.)			0	100	100	500	100
34		Adjusted rest-of-region load	13,300	14,600	14,500	13,600	13,500	14,400	13,900
35									
36		1995 Rate Case resources for 2002	12,000	12,000	12,000	12,000	12,000	12,000	12,000
37		Conservation		700	700	800	800	800	800
38		Combustion turbines		1,700	1,700	700	600	1,500	900
39		Other (effic., renewables, co-gen)		200	200	200	200	200	200
40		Adjusted rest-of-region resources	12,000	14,600	14,500	13,600	13,500	14,400	13,900
41									
42		Adjusted rest-of-region load/resource balance (resources - loads)	-1,300	0	0	0	0	0	0
43									
44	**Whole Region**	Adjusted Loads for 2002	22,300	22,200	21,700	22,500	22,500	22,800	22,500
45		Adjusted Resources for 2002	20,700	23,800	23,600	22,500	22,500	22,800	22,500
46		Adjusted load/resource balance (resources - loads)	-1,600	1,600	1,900	0	0	0	0

*Forecast of Loads and Resources used in Bonneville Power Administration's 1995 Rate Case Initial Proposal.
Note that numbers have been rounded to the nearest 100 aMW; therefore some changes appear as zero.
RC = 1995 Rate Case
RoR = Rest of Region
L/RB =Load/Resource Balance

Notes, table 4.4-8

Lines 2, 3: These are end-use consumer responses to BPA's rates as passed through by BPA's customers in retail electric rates. The judgment of BPA's technical experts was that at least 80 percent of this reduction would take the form of fuel switching, and no more than 20 percent would be conservation. BPA and total regional load change by the same amount, because this change is a price response to BPA's rates affecting only BPA loads. Note that a positive number means an increase in BPA load (i.e., a switch from natural gas to electricity in response to low BPA rates).

Line 4: This line represents a change in the DSI load forecast since the 1995 Rate Case forecast was made.

Line 5: This line represents service to this portion of DSI load as interruptible load in Status Quo and BPA Influence alternatives (balanced by amounts shown in line 13).

Lines 6 and 7: These are BPA load changes resulting from utility and DSI customer decisions, in response to BPA's contract terms and rates, to meet a portion of their load growth with their own new generation (self-generation) instead of with BPA power. While BPA's load changes, total regional load does not. These resources, with other resources built by customers to meet their loads, are shown in line 36. The quantity of customer-developed CTs depends on BPA's rates and contracts, the amount of customer load growth, and the supply of potential CT generation at or below BPA's rate.

Line 8. This is an increase in BPA loads because BPA exercises the "in-lieu" provisions of the residential exchange contracts to serve exchange loads with the BPA surplus that would otherwise exist in those alternatives. The BPA load increase on this line is balanced by a decrease in rest-of-region load on line 32.

Lines 9 and 33: This is a shift of load obligation that BPA had planned to meet with incentive conservation programs, from BPA to BPA's customers. Customers meet this load without BPA program incentives using resources of their choice. Much of this load could be met with conservation based on the Resource Program estimate of 660 aMW of cost-effective conservation in BPA customer loads by 2003.

Line 18: This is BPA-sponsored conservation. Conservation out of the 660 aMW of achievable potential not shown here is shown in line 8 as a shift of load obligation.

Line 21: The power purchases shown here are those identified in the 1992 Resource Program or those needed for planning purposes to balance BPA's loads and resources.

Line 29: These are changes in the loads of residential exchange customers in response to changes in the PF rate passed to residential and small farm end-users under the Residential Exchange Program.

Line 32: These are reductions in the loads of residential exchange customers in three alternatives because BPA exercises the "in-lieu" provisions of the exchange program to serve exchange loads itself with a portion of the BPA surplus that would otherwise exist in those alternatives.

Table 4.4-9: Summary of BPA Firm Load Changes in 2002 Compared With 1995 Rate Case Assumptions (aMW)

	Status Quo	BPA Influence	Market Driven	Maximize Financial Returns	Minimal BPA	Short-Term Marketing
Utility Load Change From Non-BPA Generation	-1,400	-600	0	-100	200	0
Utility Load Change: Price-Induced and Fuel Switching	0	0	0	100	100	0
Shift of Load Obligation	0	0	-100	-100	-500	-100
DSI Load Change From Revised Forecast	200	200	200	200	200	200
Conversion of DSI Firm Load to Interruptible	-300	-800	0	0	0	0
DSI Load Change From Non-BPA-Generation	-800	-1,500	-200	-200	-800	-800
Exchange In-Lieu Load	900	900	0	0	0	300
TOTAL BPA Firm Load Change	-1,400	-1,800	-100	0	-800	-400

Note: Positive number means BPA load increase; negative number means BPA load decrease. Rounding to nearest 100 aMW affects totals.

As table 4.4-9 shows, the Status Quo and BPA Influence alternatives lead to substantial reductions in BPA firm loads, as utilities and DSIs choose non-BPA generation in response to increases in BPA's rates. These load changes are based on the availability of resources at prices below customers' expectations of BPA's rates (see Appendix C). The line labeled "Utility Load Change: Price-Induced and Fuel Switching" reflects (in Maximize Financial Returns and Minimal BPA alternatives) a switch from natural gas to electricity because of low BPA electricity rates. The line labeled "Shift of Load Obligation" reflects a transfer of load from BPA to utility customers of BPA as they implement their own conservation programs under several of the alternatives. The line "DSI Load Change from Revised Forecast" reflects a revision in the DSI forecast since the Rate Case analysis was completed, to reflect more current predictions of higher aluminum prices and higher DSI demand (in all alternatives). The line "Conversion of DSI Firm Load to Interruptible" reflects load that is served as interruptible load in Status Quo and BPA Influence alternatives. It should be noted that load losses in the Status Quo alternative would be even higher than shown in table 4.4-9 except that BPA assumes that in this alternative (as in BPA Influence and Short-Term Marketing), BPA exercises the "in-lieu" provisions of the residential exchange contracts to serve exchange loads of IOUs itself with a portion of the surplus that BPA otherwise would have.

Table 4.4-10: Summary of BPA Firm Load Changes in 2002 Compared With the Status Quo (aMW)

	Status Quo	BPA Influence	Market Driven	Maximize Financial Returns	Minimal BPA	Short-Term Marketing
Utility Load Change From Non-BPA Generation	N/A	800	1,400	1,300	1,600	1,400
Utility Load Change: Price-Induced and Fuel Switching	N/A	0	0	100	100	0
Shift of Load Obligation	N/A	0	-100	-100	-500	-100
DSI Load Change From Revised Forecast	N/A	0	0	0	0	0
Conversion of DSI Firm Load to Interruptible		-500	300	300	300	300
DSI Load Change From Non-BPA-Generation	N/A	-700	600	600	0	0
Exchange In-Lieu Load	N/A	0	-900	-900	-900	-600
TOTAL BPA Firm Load Change	N/A	**-400**	**1,300**	**1,400**	**600**	**1,000**

Note: Positive number means BPA load increase; negative number means BPA load decrease. Rounding to nearest 100 aMW affects totals.

Table 4.4-10 displays the same information as table 4.4-9, but in terms of differences from the Status Quo predicted load losses. It shows that total BPA firm loads are greater than Status Quo loads in all alternatives except for BPA Influence. That alternative incorporates the “DSI Firm Service in Spring Only” module, which leads to the transfer of over half of the DSI load from BPA to self-generation or other non-BPA sources. In other alternatives, BPA’s average rates and/or contract terms are such that BPA retains most utility load and some of the DSI loads lost in Status Quo. In addition, BPA does not serve “in-lieu” loads of IOUs (except in BPA Influence and Short-Term Marketing alternatives).

It is important to recognize that conclusions about utilities or DSIs replacing BPA power with non-BPA generation do not apply to all of BPA's wholesale customers. For some utilities, it may not be feasible to purchase non-BPA generation, given the administrative and technical demands of financing, siting, negotiating delivery, securing services, arranging for operation and dispatch, providing reserves, and other requirements for acquisition of non-BPA resources. For these utilities, there may be no practical alternative to continuing to purchase BPA power. Increases in BPA's rates to meet BPA's revenue requirements, such as those noted for the Status Quo alternative, would be passed along to consumers.

In some cases, passing BPA rate increases (such as those in the Status Quo or BPA Influence alternatives) through to retail consumers could cause hardships. Rural utilities with large service territories often have high distribution costs which result in high rates even without the effects of BPA power. Further increases in retail rates could have a variety of consequences, including reductions in loads due to the development of generation by industrial consumers, or closures of marginal industries and businesses unable to absorb increases in power costs.

In extreme cases, the utility itself might not be able to continue as a viable business operation in the face of increased wholesale power costs. A utility in economic distress could voluntarily seek to consolidate with neighboring utilities, or could sell its facilities for new public or private owners to operate. If there were no interested buyers, the management of a distressed utility might be turned over to a receiver or a trustee to control operations and restore stability. In the worst case, it is conceivable that a distressed utility might be relieved of the obligation to serve some high-cost consumers, leaving those consumers without conventional utility service.

4.4.3.3 Resource Development

Resource development among the EIS alternatives is shown in tables 4.4-11 through 4.4-13 and figure 4.4-2. BPA would have surpluses of about 1,600 aMW and 1,900 aMW, respectively, under the Status Quo and BPA Influence alternatives, and load-resource balance under the other alternatives. (The analysis assumed that the rest of the region acquired just enough resources to achieve load-resource balance under medium loads in all other alternatives.) The surpluses are the combined effect of BPA load losses and the completion of acquisitions BPA has previously committed to under its resource acquisition program.

Table 4.4-11 also shows how BPA conservation acquisition varies among the alternatives. In comparing the alternatives, it is important to note the extent to which conservation in BPA loads achieves the target of 660 aMW of cost-effective conservation potential by 2003 that BPA established in its 1992 Resource Program. Because the alternatives differ from the Status Quo in their strategies for conservation, the level achieved in the region must be assessed based on more than the results of BPA programs and market transformation activities. Other influences include energy efficiency codes and standards already in place, utility-sponsored conservation independent of BPA-sponsored programs, and price-induced conservation resulting from rate increases. These influences, and the amounts of conservation achieved by 2002 and by 2003, are shown in table 4.4-14. The table includes the effect of the “Fully Funded Conservation” module on the Market-Driven, Maximize BPA Financial Returns, and Short-Term Marketing alternatives. “Fully Funded Conservation” is intrinsic to the Status Quo and BPA Influence alternatives, and does not apply to the Minimum BPA alternative. Conservation amounts for the year 2003 are also shown because 2003 was the year by which the target was to be achieved, although the study period for this EIS ends in 2002.

As the table shows, the highest level of conservation in BPA loads occurs under the Status Quo and BPA Influence alternatives and the “fully funded” modules on the Market-Driven and Maximum Financial Returns alternatives, with somewhat lesser levels of achievement under the Market-Driven alternative. Under the BPA Influence alternative and the Fully Funded Conservation module, BPA-sponsored region-wide programs would probably take the place of utility-sponsored programs that were expected under all the other alternatives to the Status Quo. Total conservation would be lower under the Short-Term Marketing alternative, still lower under Maximize Financial Returns, and least under the Minimal BPA Marketing alternative, where the absence of BPA-sponsored conservation actions, together with low prices for Federal power, would leave conservation to utility-sponsored programs.

Except in the Status Quo and BPA Influence alternatives, the numerical analysis of alternatives was developed under the assumption that the rest of the region (other than BPA) would develop precisely enough resources to serve the medium forecast loads. This simplifying assumption facilitates comparisons among the alternatives, but actual development is unlikely to match loads so well.

If utilities are acquiring resources independently, there is likely to be some excess development due to imperfect coordination and planning of resources. Some utilities might over-build as a precaution in case loads are higher than the medium forecast. Others might deliberately over-build with the intent to market excess capability until it is needed for the utility’s own loads. If too many developers build resources, the market might not be large enough to consume all of the power available. If utilities decide to purchase power rather than developing their own resources, the tendency to over-build might be reduced, as localized surpluses balance out against loads in areas relying on spot market purchases.

An excess of thermal generation might lead to permanent shutdowns of some facilities, leaving the owners to bear the costs of the stranded investment. If the owner of an abandoned resource is a utility, the owners of the utility, whether stockholders or consumers, will likely bear the costs of such stranded investments.

Table 4.4-11: BPA New Resource Acquisitions by 2002 (aMW)

	Alternatives					
Generation/Conservation Resource Types	**Status Quo**	**BPA Influence**	**Market-Driven (Proposed Action)**	**Maximize Financial Returns**	**Minimal BPA**	**Short-Term Marketing**
Conservation	600	600	460	260	130	350
Solar	0	0	0	0	0	0
Muni Solid Waste	0	0	0	0	0	0
Geothermal	60	260	60	60	0	0
Wind	20	120	20	20	0	0
Hydroelectric	0	0	0	0	0	0
Combustion Turbines	300	130	130	130	130	130
Cogeneration	100	100	100	100	100	100
Nuclear	0	0	0	0	0	0
Coal	0	0	0	0	0	0
Efficiency Improvements	50	50	50	50	50	50
Power Purchases	200	0	190	470	0	80
TOTAL	**1,320**	**1,250**	**1,000**	**1,070**	**400**	**700**

Note: Amounts are rounded to nearest 10 aMW, which may affect totals.

Table 4.4-12: Other Utilities' New Resource Acquisitions by 2002 (aMW)

	Alternatives					
Conservation/Generation Resource Types	**Status Quo**	**BPA Influence**	**Market-Driven (Proposed Action)**	**Maximize Financial Returns**	**Minimal BPA**	**Short-Term Marketing**
Conservation	690	690	800	800	800	800
Solar	0	0	0	0	0	0
Muni Solid Waste	0	0	0	0	0	0
Geothermal	40	40	40	40	40	40
Wind	60	60	60	60	60	60
Hydroelectric	0	0	0	0	0	0
Combustion Turbines	1,740	1,660	690	560	1,530	940
Cogeneration	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0
Coal	0	0	0	0	0	0
Efficiency Improvements	80	80	80	80	80	80
Power Purchases	0	0	0	0	0	0
TOTAL	**2,600**	**2,520**	**1,660**	**1,520**	**2,500**	**1,910**

Note: Amounts are rounded to nearest 10 aMW, which may affect totals.

Table 4.4-13: Regional New Resource Acquisitions by 2002 (aMW)

	Alternatives (aMW)					
Conservation/Generation Resource Types	**Status Quo**	**BPA Influence**	**Market-Driven (Proposed Action)**	**Maximize Financial Returns**	**Minimal BPA**	**Short-Term Marketing**
Conservation	1,280	1,280	1,250	1,050	920	1,140
Solar	0	0	0	0	0	0
Municipal Waste	0	0	0	0	0	0
Geothermal	100	300	100	100	40	40
Wind	80	180	80	80	60	60
Hydroelectric	0	0	0	0	0	0
Combustion Turbines	2,040	1,790	820	680	1,660	1,070
Cogeneration	100	100	100	100	100	100
Nuclear	0	0	0	0	0	0
Coal	0	0	0	0	0	0
Efficiency Improvements	120	120	120	120	120	120
Power Purchases	200	0	190	470	0	80
TOTAL	**3,910**	**3,770**	**2,650**	**2,600**	**2,900**	**2,600**
Fuel Switching*	160	210	180	80	50	170

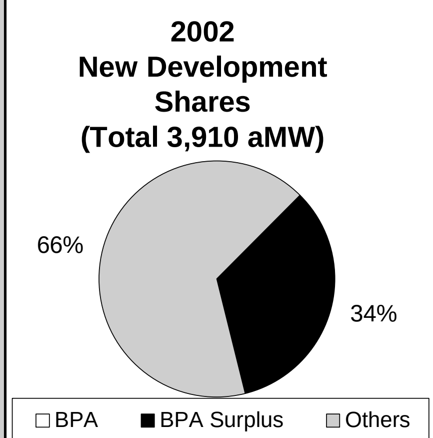
Note: Amounts are rounded to nearest 10 aMW, which may affect totals.

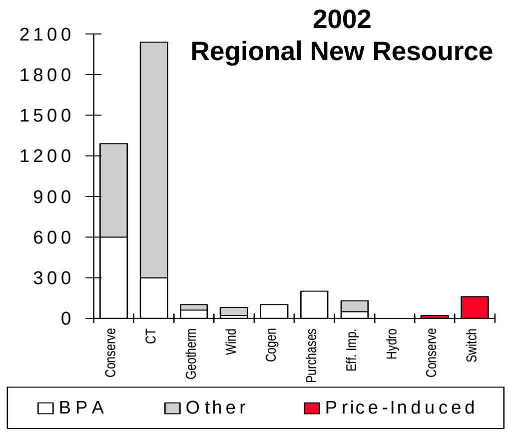
*Tables 4.4-9 and 4.4-10 show BPA firm load changes; the amounts shown here are load *losses* due to fuel switching; the smaller load losses shown here for Maximize Financial Returns and Minimal BPA are the source of the relative load gains to BPA (rounded to the nearest hundred aMW) shown in tables 4.4-9 and 4.4-10.

FIGURE 4.4-2

New Resource Development By 2002*
Based on 1995 Rate Case Load Forecast

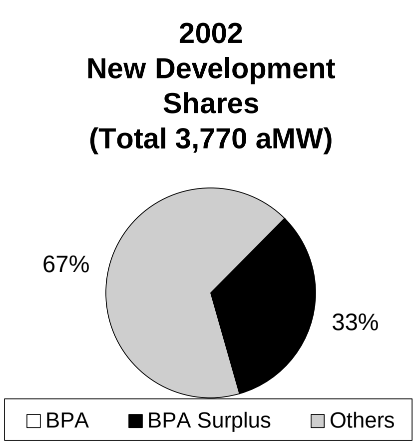
Status Quo

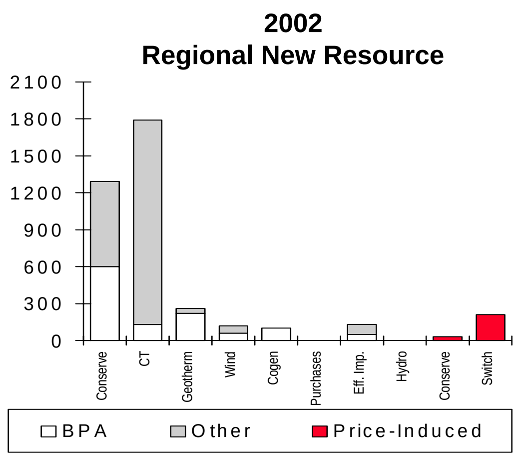




Resource	*BPA*	*Other*
Conservation	* 600	690
CTs	300	1,740
Geothermal	60	40
Wind	20	60
Cogen	100	0
Purchases	200	0
Eff Improve	50	80
Hydro	0	0
Price-Induced:		
Conservation		20
Fuel Switch		160

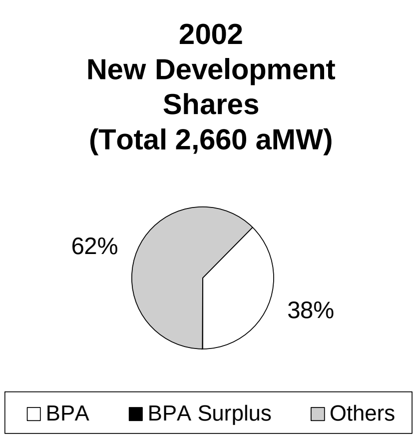
BPA Influence

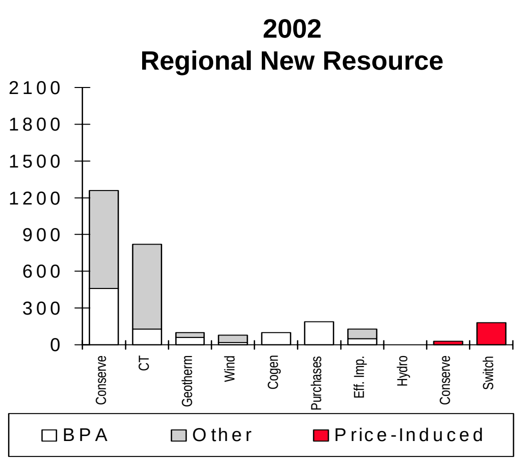




Resource	*BPA*	*Other*
Conservation	* 600	690
CTs	130	1,660
Geothermal	260	40
Wind	120	60
Cogen	100	0
Purchases	0	0
Eff Improve	50	80
Hydro	0	0
Price-Induced:		
Conservation		30
Fuel Switch		210

Market Driven BPA





Resource	*BPA*	*Other*
Conservation	* 460	800
CTs	130	690
Geothermal	60	40
Wind	20	60
Cogen	100	0
Purchases	190	0
Eff Improve	50	80
Hydro	0	0
Price-Induced:		
Conservation		30
Fuel Switch		180

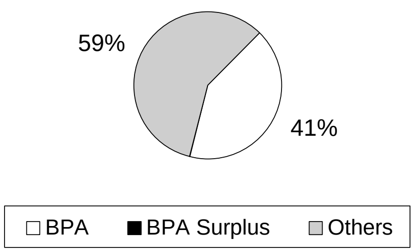
***** The numbers reflected are for 2002. The Status Quo, BPA Influence, and Market Driven alternatives remain committed to the 660 aMW target for 2003: Status Quo 640 aMW BPA-funded and 70 aMW independent utility designed/consumer response; BPA Influence 640 aMW BPA-funded and 90 aMW independent utility designed/consumer response; and Market Driven 480 aMW BPA-funded, and 200 aMW independent utility designed/consumer response.

FIGURE 4.4-2 (continued)

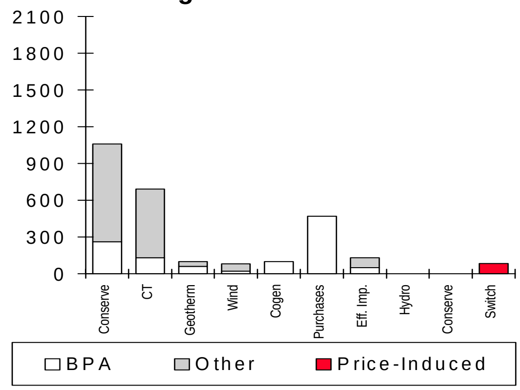
New Resource Development By 2002

Max Fin Returns

2002 New Development Shares (Total 2,600 aMW)



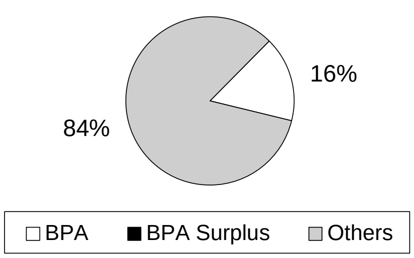
2002 Regional New Resource



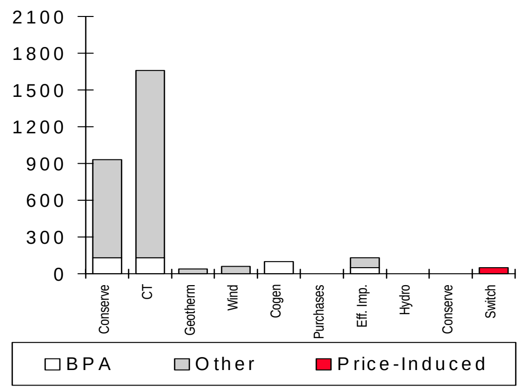
Resource	*BPA*	*Other*
Conservation	260	800
CTs	130	560
Geothermal	60	40
Wind	20	60
Cogen	100	0
Purchases	470	0
Eff Improve	50	80
Hydro	0	0
Price-Induced:		
Conservation		0
Fuel Switch		80

Minimal BPA

2002 New Development Shares (Total 2,900 aMW)



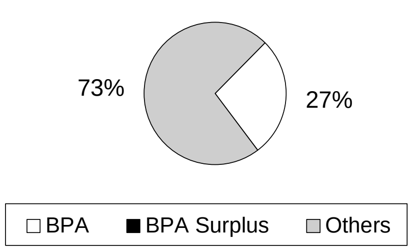
2002 Regional New Resource



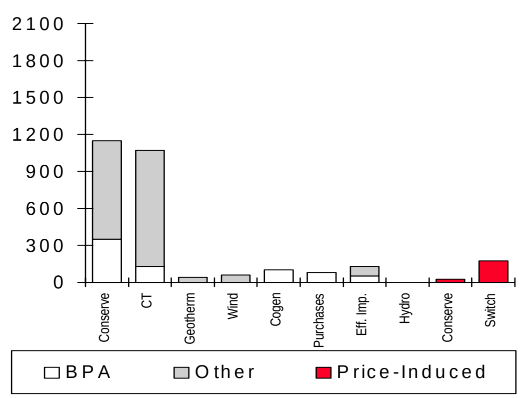
Resource	*BPA*	*Other*
Conservation	130	800
CTs	130	1530
Geothermal	0	40
Wind	0	60
Cogen	100	0
Purchases	0	0
Eff Improve	50	80
Hydro	0	0
Price-Induced:		
Conservation		-10
Fuel Switch		50

Short Term Mktg

2002 New Development Shares (Total 2,620 aMW)



2002 Regional New Resource



Resource	*BPA*	*Other*
Conservation	350	800
CTs	130	940
Geothermal	0	40
Wind	0	60
Cogen	100	0
Purchases	80	0
Eff Improve	50	80
Hydro	0	0
Price-Induced:		
Conservation		20
Fuel Switch		170

Table 4.4-14: Breakdown of Energy Conservation in BPA Loads by 2002 and by 2003 (aMW)
(With and Without "Fully Funded Conservation" Module)

Source of Conservation	Status Quo	BPA Influence	Market-Driven	Market-Driven with "Fully Funded" Conser-vation Module	Maximize Financial Returns	Maximize Financial Returns with "Fully Funded" Conser-vation Module	Minimal BPA	Short-Term Marketing	Short-Term Marketing with "Fully Funded" Conser-vation Module
Already Achieved by FY 1993	80	80	80	80	80	80	80	80	80
Committed Under Existing BPA Programs	200	200	200	200	0	200	0	200	200
Additional BPA Efforts	270	250	0	140	0	140	0	0	250
BPA Market Transformation	0	20	20	20	20	20	0	20	20
Effect of Enacted Codes and Standards	50	50	50	50	50	50	50	50	50
BPA TOTAL	**600**	**600**	**350**	**490**	**150**	**490**	**130**	**350**	**600**
Independent Utility Programs	**20**	**20**	**130**	**20**	**130**	**20**	**130**	**130**	**20**
BPA Energy Service Products[2]	0	0	110	110	110	110	0	0	0
Price-Induced Consumer Actions[3]	20	30	30	30	0	0	-10	20	20
Potential Lost to Fuel-Switching[2]	20	20	20	20	10	30	0	20	20
NON-BPA TOTAL	**60**	**70**	**290**	**180**	**250**	**160**	**120**	**170**	**60**
TOTAL CONSERVATION FOR BPA LOADS IN 2002	**660**	**670**	**640**	**670**	**400**	**650**	**250**	**520**	**660**
TOTAL CONSERVATION FOR BPA LOADS IN 2003[4]	**710**	**730**	**680**	**710**	**430**	**660**	**270**	**560**	**710**

Note: Rounding to nearest 10 aMW affects totals and subtotals.

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[2] BPA Energy Service Products support utility programs, so are listed separately from the BPA total. "Potential Lost to Fuel Switching" is conservation potential included in the Council's goal that is no longer available because the electrical load to be made more efficient through conservation has switched to natural gas.

[3] Price-induced load changes and fuel switching are net of Status Quo amounts projected in the 1995 Rate Case.

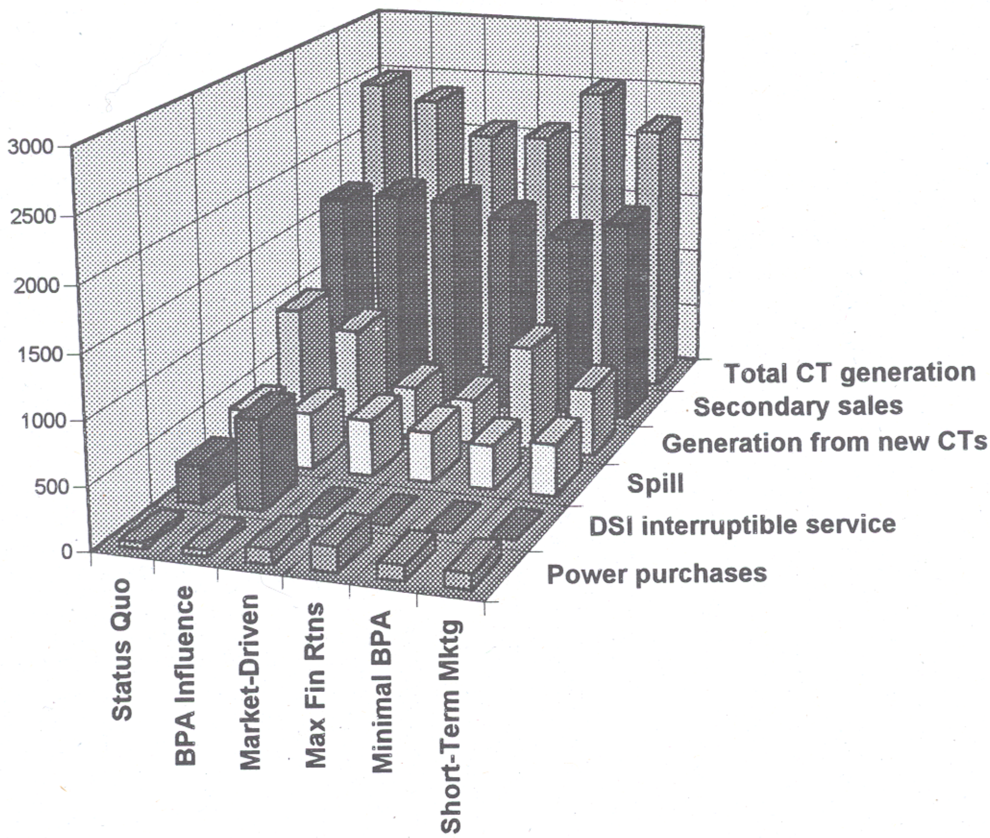
[4] Projected total conservation in 2003.

4.4.3.4 Resource Operations

Figure 4.4-3 and table 4.4-15 show resource operations across the alternatives.

Resource operations vary across the alternatives in the total amount of generation from CTs, the amount of BPA secondary energy sales, the amount of spill that occurs at hydro generating projects, the power available to the DSI top quartile (in Status Quo and BPA Influence alternatives only), and the amount of operating year purchases BPA makes to meet loads. Streamflow significantly affects operations, as nonfirm hydro displaces thermal generation from CTs and other displaceable thermal generation.

Figure 4.4-3: Regional Operations Summary



Notes, figure 4.4-3:
For each alternative, these output variables were averaged over the 14 operating periods in 2002 (formerly 2003) and averaged over 50 different hydro years.
Total CT Generation: Average MW produced by all high-cost resources = new CTs + existing high-cost thermals (mainly CTs but also including import contracts for this analysis).
Secondary Sales: Average sales of nonfirm energy to California.
Generation From New CTs: Average MW of generation from CTs built by BPA or others to meet load growth between now and 2002 (formerly 2003).
Spill: Average amount of power not able to be sold. (Tools used in the BP EIS did not reflect all actual markets, especially low-cost thermal displacement market. Most spill reported occurs April through June.)
DSI Top Quartile Service: Average MW of energy supplied to DSI top quartile (nonfirm portion of DSI load). Size of top quartile varies across alternatives.
Power Purchases: Average quantities of energy purchased from the spot market during operations under specific hydro conditions. (Not the same as the amount of *planned* power purchases included in load/resource balances.)

Table 4.4-15: Operations of Thermal Generation, Power Purchases, Spill, and DSIs (aMW)

Parameter	Status Quo	BPA Influence	Market-Driven (Proposed Action)	Maximize Financial Returns	Minimal BPA	Short-Term Marketing
Spill	**400**	**500**	**500**	**400**	**300**	**400**
Alum. DSI Firm Load (a)	1,500	400	2,300	2,300	1,800	1,700
Non-Alum. DSI Firm Load (a)	100	0	200	200	200	200
Alum. DSI Top Quartile Service (a)	300	700	0	0	0	0
Non-Alum. DSI Top Quartile Service (a)	0	100	0	0	0	0
Alum. DSI Ops. from Self-Gen. (a)	700	1,400	200	200	700	700
Non-Alum. DSI Ops. from Self-Gen. (a)	100	100	0	0	100	0
Total Alum. DSI Operations.	**2,500**	**2,500**	**2,500**	**2,500**	**2,500**	**2,500**
Total Non-Alum. DSI Operations	**200**	**200**	**200**	**200**	**200**	**200**
Total DSI Operations	**2,700**	**2,700**	**2,700**	**2,700**	**2,700**	**2,700**
Older CTs	1,500	1,500	1,700	1,700	1,700	1,700
Coal	3,200	3,100	3,400	3,500	3,400	3,400
Newer CTs	1,000	800	400	400	900	600
WNP-2	900	900	900	900	900	900
Total Thermal Operations	**6,500**	**6,300**	**6,400**	**6,500**	**6,900**	**6,600**
Operating Year Purchases	**0**	**0**	**100**	**200**	**100**	**100**
Secondary Sales	**1,700**	**1,800**	**1,700**	**1,600**	**1,500**	**1,600**

Note: Loads rounded to nearest 100 aMW (thus some positive numbers round to zero).
(a) DSI loads from 1993 Pacific Northwest Loads and Resources Study, table 2 plus predicted load changes for each alternative.

The potential for termination of existing resources due to operating costs above market prices could alter these values, necessitating replacement power purchases.

4.4.3.5 Capacity

The analysis of resource operations above addresses only operations to meet firm energy requirements and to market any surplus capability. Although peak demands might present different issues of resource operations, there is insufficient evidence of changes in the hourly demands on BPA's system to infer that there would be significant peak resource development or operations impacts in any of the alternatives.

BPA's ability to make long-term extraregional sales of products and/or services is restricted by the provisions of the regional preference act (Public Law 88-552). The load within the region is being met adequately with its current resources, and it is not yet clear that unbundling of power products and services or other BPA marketing efforts would significantly change the basic hourly load shape of the region. For example, if a BPA customer currently purchasing shaped energy from BPA decides to purchase flat energy somewhere else and purchase shaping only from BPA, its load shape does not change. The customer will have approximately the same need for shifting energy into peak periods as when it was purchasing shaped energy from BPA. The shaping burden the BPA system would have to meet would probably not be substantially different.

In the event that capacity or shaping demand begins to outstrip BPA's capability, some options for meeting the demand are more attractive than resource development. The first response, in the short term, would be increased spot-market purchases. Longer-term responses would probably place DSM ahead of resource acquisitions. For example, in most other regions of the country, resource development is driven by the need to meet the highest single-hour load a utility will face. This gives the utility a strong incentive to pursue DSM tools that reduce the magnitude of the single-hour peak. Many such peak-management measures have been developed, and the utility industry has accumulated a lot of experience with some. Few of these have been implemented in this region, so even the lowest-cost and most easily implemented DSM savings have not been developed in the PNW. Time-of-use rates alone could probably flatten PNW peak loads substantially. DSM efforts are likely to be the most attractive choice if BPA needs to increase its shaping capability or sustained peaking capacity.

One factor that affects BPA's capacity is the level of nighttime load. When nighttime loads are not much greater than minimum flow requirements, the system has little ability to take in energy at night to store for use in the next heavy-load period, and may have to spill energy received at night. While this does not affect the system's ability to meet peak loads, it affects its ability to derive benefits from energy received at night; it might may require purchasing energy within the next month to replace the energy delivered on peak that could not be returned at night.

The level of DSI load is a major variable in the level of Federal system nighttime loads because this load is large, and it is flat (constant around the clock). Compared to the Status Quo alternative, the total DSI loads on BPA decrease in the BPA Influence alternative by almost 700 aMW, and increase in the Market-Driven and Maximize Financial Returns alternatives by 1,300 aMW and by 100 aMW in the Minimal BPA alternative. For the Short-Term Marketing alternative, DSI loads stay the same as under Status Quo. This means that it could be easier to utilize nighttime energy in alternatives other than Status Quo, BPA Influence and Short-Term Marketing. (See table 4.4-18 in section 4.4.3.7).

4.4.3.6 Transmission System Development and Operation

Figure 4.4-4 and table 4.4-16 show the amount of major transmission line development by BPA and other parties expected under each of the alternatives. Projections include additions to the interconnected transmission system in the Northwest Power Pool (NWPP) area (all of Washington, Oregon, Idaho, Montana, Utah, British Columbia, Alberta, most of Nevada, and western Wyoming).

FIGURE 4.4-4

Key Transmission Changes By 2003
Derived from BPA and WSCC Forecasts

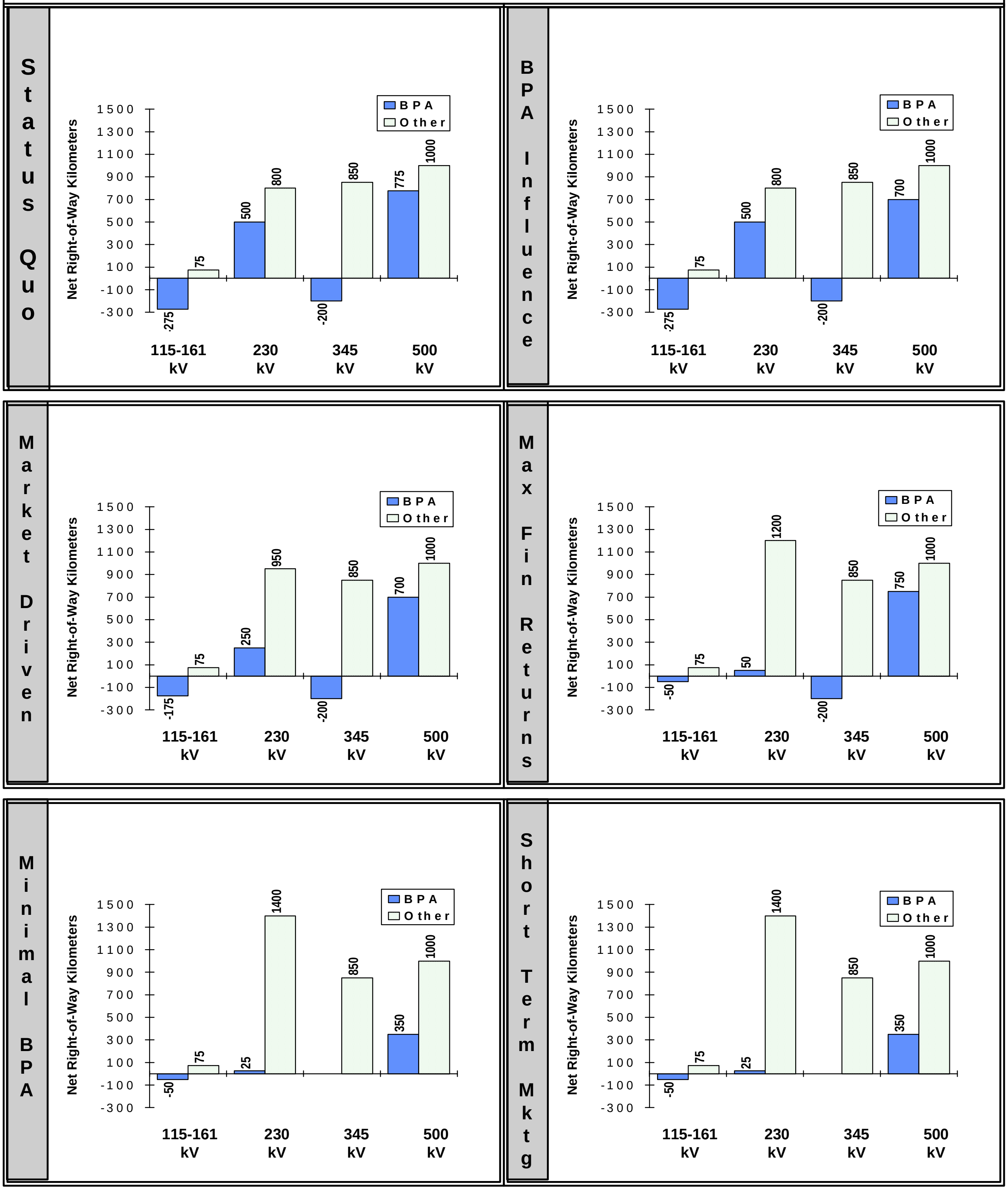


Table 4.4-16: Summary of Significant Transmission Additions in the Northwest Power Pool Area by 2002 (Net Right-of-Way Kilometers)

Transmission Voltage Class	Status Quo			BPA Influence			Market-Driven (Proposed Action)		
	BPA	Other	Region	BPA	Other	Region	BPA	Other	Region
115-161 kV	-275	75	-200	-275	75	-200	-175	75	-100
230 kV	500	800	1,300	500	800	1,300	250	950	1,200
345 kV	-200	850	650	-200	850	650	-200	850	650
500 kV	775	1,000	1,800	700	1,000	1,700	700	1,000	1,700
Total	800	2,725	1,800	725	2,725	1,700	575	2,875	1,700

Transmission Voltage Class	Max. Financial Returns			Minimal BPA			Short-Term Marketing		
				BPA	Other	Region	BPA	Other	Region
	BPA	Other	Region	BPA	Other	Region	BPA	Other	Region
115-161 kV	-50	75	25	-50	75	25	-50	75	25
230 kV	50	1,200	1,250	25	1,400	1,425	25	1,400	1,425
345 kV	-200	850	650	00	850	850	00	850	850
500 kV	750	1,000	1,750	350	1,000	1,350	350	1,000	1,350
Total	550	3,125	3,675	325	3,325	3,650	325	3,325	3,650

Note: Negative numbers indicate net kilometers of line taken out of service (typically for upgrading to a higher voltage)

Source: Compiled from WSCC "Coordinated Bulk Power Supply Program" 1992-2002, Reply to U.S. Department of Energy Form OE-411, April 1, 1993; "BPA Transmission System Facilities Ten-Year Development 1993-2003," Office of Engineering, September, 1993; and draft updates provided from BPA to WSCC in March 1994.

The projections were drawn from WSCC and BPA 10-year plans for the NWPP area. The amounts of transmission facilities represent kilometers of new construction; they do not include projects for which only a change in operating voltage is required. Amounts represent right-of-way kilometers, not circuit kilometers; in several cases, projects remove an existing single-circuit, lower-voltage line and replace it with a double-circuit, higher-voltage line. Negative numbers mean that more kilometers of that voltage are removed than constructed. Projects labeled "tentative" were not included. In addition, local transmission and subtransmission additions are not included in these projections—only transmission additions to the interconnected system. It should be noted that the amounts of proposed development in table 4.4-16 reflect a predominant role for BPA in regional 500-kV transmission development. The 850 kilometers of 345-kV and 1,000 kilometers of 500-kV transmission facilities shown for other utilities all represent proposed intertie projects linking the PNW to other regions; those projects are assumed to occur in all alternatives.

The table shows that, while BPA's share of new regional transmission development is reduced by as much as 60 percent in some alternatives, overall development in the region varies only by about 6 percent.

4.4.3.7 Consumer Behavior

Retail Sector Rate Effects

The effect on bills of ultimate consumers is difficult to predict with any degree of accuracy. Retail rate effects for a particular utility would depend on the ratio of BPA-purchased power costs to total costs and the total kWh sales for the utility. For example, if BPA-purchased power costs represented 50 percent of a full requirements customer's total costs, then a 10-percent increase in power costs would lead to a 5-percent increase in the utility's total costs. Hypothetical retail rates for consumers of two types of BPA customers are shown in table 4.4-17.

Table 4.4-17: Retail Price Effect of BPA Rate Changes (Hypothetical) (mills/kWh)

Alternative	Status Quo	BPA Influence	Market-Driven BPA	Maximize Financial Returns	Minimal BPA	Short-Term Marketing
Hypothetical Full Requirements Customer[1]	53-59	51-57	50-56	50-56	49-55	50-56
Hypothetical Partial Requirements Customer[2]	30-36	30-36	29-35	29-35	29-35	29-35

[1] 100 percent of power purchased from BPA.

[2] 50 percent of power purchased from BPA.

DSI Load Effects

The changes in aluminum smelter loads resulting from increases in BPA's electric rates were estimated relative to the BPA 1995 Rate Case long-term forecast. The changes in DSI firm and nonfirm loads compared to the 1995 Rate Case loads are in table 4.4-18 below.

Table 4.4-18: BPA DSI Load Change Relative to the 1995 Rate Case (aMW in 2002)

	Status Quo	BPA Influence	Market Driven	Maximize Financial Returns	Minimal BPA	Short-Term Marketing
BPA DSI Firm Load Change From Revised Forecast	200	200	200	200	200	200
Conversion of DSI Firm Load to Interruptible	-300	-800	0	0	0	0
BPA DSI Firm Load Change From Non-BPA-Generation	-800	-1,500	-200	-200	-800	-800
DSI Load Served As Interruptible	300	800	0	0	0	0
Total BPA DSI Load	**-600**	**-1,300**	**0**	**0**	**-600**	**-600**
Total DSI Loads	**2,700**	**2,700**	**2,700**	**2,700**	**2,700**	**2,700**

Note: Positive number means BPA load increase; negative number means BPA load decrease.

Aluminum smelter firm loads increased by approximately 200 aMW under all alternatives because DSI load information was updated from the information used in the 1995 Rate Case to reflect a higher expected load for the DSIs. In addition, in all alternatives, based on the availability of power from other sources at relatively low prices, it is assumed that if DSIs are not served by BPA, they can find competitive sources of electricity from non-BPA sources. Therefore, in all alternatives it is assumed that DSI output and total DSI load does not change, even if in some alternatives BPA DSI loads decline.

The Status Quo alternative is similar to the 1995 Rate Case (base), except that, in this alternative, BPA continues to provide DSI top quartile service (as in current DSI contracts). At the same time, the increase in BPA's rates overall, and the DSI VI rate in particular, cause approximately 800 aMW of DSI load to shift load away from BPA and to be served instead by self-generation or other suppliers.

Under the BPA Influence alternative, DSIs are offered firm service only in the spring, when Columbia River system flows are high. BPA DSI firm loads are reduced to the amount served as firm (about one-third of their total BPA load). The remainder of their load is assumed to be served by self-generation or by other suppliers. The DSI load BPA serves is less than half of the total DSI load in the region, but only about a third of the diminished BPA load is firm, due to interruptible service to the entire BPA load outside of the spring flow period.

The Market-Driven alternative has tiered rates in the long term (in the short term, rates are implemented without tiered rates), with a Tier 2 rate that DSIs generally would be unwilling to pay; in addition, the amount of firm service offered to DSIs from Tier 1 power will decline over time in order to provide additional Tier 1 power to preference customers. Nonetheless, because in this alternative BPA is able to keep rates lower than in Status Quo, BPA is able to retain approximately 600 aMW of the load loss to other power sources that occurs in Status Quo.

In the Maximize Financial Returns alternative, BPA offers the DSIs contracts providing for 100-percent firm service. Because of cost-cutting and the elimination of programs that do not produce a short-term financial return, BPA is able to reduce rates and retain DSI load, retaining 600 aMW of loads lost in the Status Quo alternative.

In the Minimal BPA alternative, BPA does not acquire significant new resources to serve load. The DSIs are offered firm service to the extent firm power is available after preference customer firm loads are met. Over time, with BPA not making resource additions, the amount of firm power available to DSIs declines, and BPA loses 600 aMW of DSI loads (the same as in Status Quo).

In the Short-Term Marketing alternative, BPA offers only short-term firm contracts, offers DSIs declining Tier 1 firm service, and prices Tier 2 power at a market-based rate. New resource acquisitions to serve firm load are almost as low as in the Minimal BPA alternative. DSI load losses are as great as in Status Quo (that is, approximately 600 aMW).

4.4.3.8 Environmental Impacts

Environmental impacts of alternatives were assessed by linking the market responses identified above in section 4.4.2 (e.g., new generation and conservation development and operations and transmission development) with the generic environmental impacts described in section 4.3.

Key regional environmental impacts are shown in table 4.4-19 and in figure 4.4-5.

Differences in impacts among the EIS alternatives are dominated by impacts of the operation of thermal generation, including existing coal and CTs, and new CTs.

The major influences on the cumulative impacts of the alternatives are the following:

- Impacts of generation are affected most by the amount of load and the types of generation operated.
- Impacts tend to be less under alternatives with small loads. The smaller regional loads are, the smaller the environmental impacts of meeting loads.
- DSI operations and environmental impacts are projected to be the same under all alternatives (although the share of their load served by BPA varies by alternative).
- Impacts are less under alternatives with more total regional conservation. For a given load level, the more conservation or cleaner generating resources are used, the smaller the impacts of meeting load. Most expected new generating resources for the next decade are either conservation or gas-fired CTs. Since conservation has few adverse impacts, the more conservation is developed, through either BPA-sponsored or independent utility efforts, the smaller the impacts of meeting load.

Table 4.4-19: Key Environmental Impacts of Alternatives Under 1994-1998 Biological Opinion Hydro Operation

Effect	Unit	Status Quo	BPA Influence	Market Driven (Proposed Action)	Maximize Financial Returns	Minimal BPA	Short-Term Marketing
New Resource Development (Impacts From the Operation of New Generating Resources)							
SO2 (a)	Tons	0	0	0	0	0	0
NOx (a)	Tons	400	400	200	200	400	300
TSP (a)	Tons	200	100	100	100	100	100
CO (a)	Tons	600	500	300	200	500	400
CO2 (a)	Tons	3,233,000	2,813,000	1,375,000	1,203,000	2,988,000	1,991,000
Water Consumption (a)	Cubic Meters	4,093,000	3,561,000	1,740,000	1,522,000	3,783,000	2,520,000
Land Use (b)	Hectares	900	1,900	800	800	700	700
Existing Generating Resources (Impacts From the Operation of Existing Thermal Resources)							
SO2 (c)	Tons	27,300	27,400	29,400	30,200	29,400	29,400
NOx (c)	Tons	76,000	74,800	82,100	84,500	82,100	82,100
TSP (c)	Tons	4,130	4,150	4,450	4,580	4,450	4,450
CO (c)	Tons	7,890	7,920	8,590	8,870	8,590	8,590
CO2 (c)	Tons	33,245,000	33,783,000	35,966,000	37,045,000	35,969,000	35,969,000
Water Consumption (c)	Cubic Meters	65,258,000	65,562,000	69,137,000	70,675,000	69,141,000	69,141,000
Hydro Operations							
Spill (d)	aMW	430	460	500	410	300	420
Power Sales and Purchases (Impacts From Net Changes in Regional and Extraregional CT Operations)							
SO2 (e)	Tons	0	0	0	0	0	0
NOx (e)	Tons	-8,600	-9,200	-8,500	-7,500	-7,200	-8,000
TSP (e)	Tons	0	0	0	0	0	0
CO (e)	Tons	-3,300	-3,500	-3,300	-2,900	-2,800	-3,100
CO2 (e)	Tons	-5,778,000	-6,203,000	-5,693,000	-5,045,000	-4,853,000	-5,409,000
Water Consumption (e)	Cubic Meters	-6,840,000	-7,343,000	-6,739,000	-5,972,000	-5,746,000	-6,916,000
Aluminum DSIs							
SO2 (f)	Tons	2,600	2,600	2,600	2,600	2,600	2,600
NOx (f)	Tons	0	0	0	0	0	0
TSP (f)	Tons	4,400	4,400	4,400	4,400	4,400	4,400
CO (f)	Tons	160,300	160,300	160,300	160,300	160,300	160,300
CO2 (f)	Tons	834,000	834,000	834,000	834,000	834,000	834,000
Water Consumption (f)	Cubic Meters	33,741,000	33,741,000	33,741,000	33,741,000	33,741,000	33,741,000
Transmission Development							
Land Use (g)	Hectares	14,300	14,000	13,900	14,700	14,300	14,300
Consumer Behavior							
Employment Change (h)	Percent	1.90%	NSSC	NSSC	NSSC	NSSC	NSSC
Fuel Switching Air Emissions							
NOx (i)	Tons	400	500	400	200	100	400
CO (i)	Tons	200	200	200	100	100	200

Notes, table 4.4-19:

NSSC = No statistically significant change.

(a) Emissions from new CTs; new resource operations from table 4.4-15 emissions coefficients from table 4.3-1 (new CTs).

(b) Includes all resource types; new resource acquisitions from table 4.4-13 land use coefficients from table 4.3-1.

(c) Emissions from existing CTs and coal; existing operations from table 4.4-15; emissions factors from table 4.3-1 (older CTs and coal).

(d) Spill at Federal hydro projects, from table 4.4-15.

(e) Reductions in emissions from CTs displaced by surplus sales from the PNW minus power purchases; secondary sales and purchases from table 4.4-15; (older CTs) emissions factors from table 4.3-1.

(f) Aluminum operations served as DSI firm, top quartile, and self-generation from table 4.4-15; emissions factors from table 4.3-1.

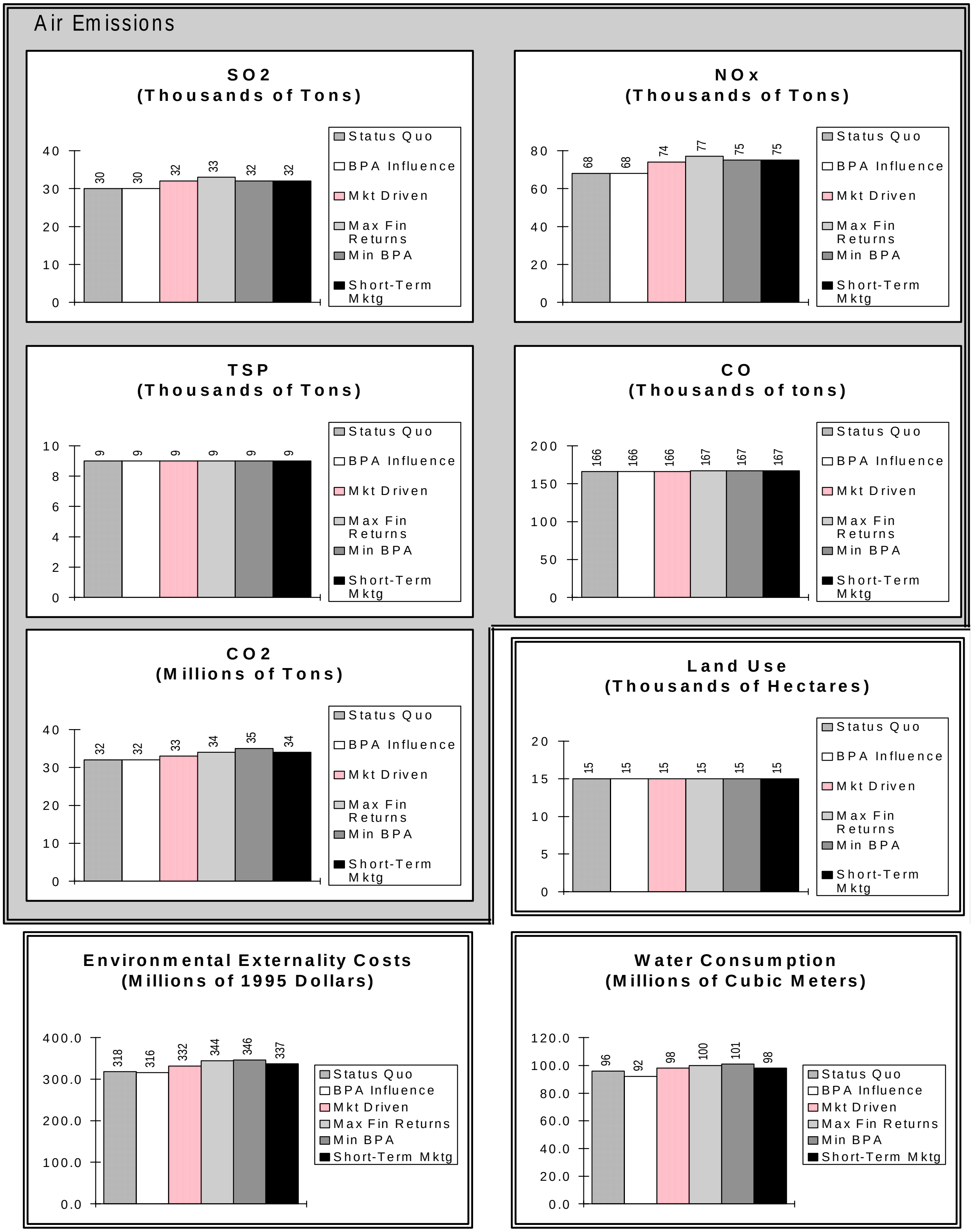
(g) Land use associated with new BPA and non-BPA regional transmission lines; transmission line miles from table 4.4-16; land use coefficients from table 4.3-1.

(h) Status Quo amount (1.9%) is annual regional employment growth in 2003; no statistically significant changes in employment growth rates among alternatives.

(i) Air emissions from fuel switching based on amount of fuel switching (table 4.4-13) and fuel switching air emissions coefficients (table 4.3-1); offsetting reduction in power plant operations included in New Resource Development entries.

FIGURE 4.4-5

Summary of Key Regional Environmental Impacts



Employment impacts **had no statistical difference across alternatives.**

Alternatives that show higher operations of existing coal resources tend to have higher overall environmental impacts. Paradoxically, in those alternatives with higher new CT acquisition (e.g., Status Quo and BPA Influence), the impacts on air from the operation of thermal generation are less, because the surplus firm power in those alternatives is used to displace older, higher-cost, dirtier coal resources (such as Valmy, Centralia, and Boardman). Alternatives with lower new thermal generating resource acquisition (such as Market-Driven BPA and Maximize Financial Returns) show higher thermal operation impacts (because more coal is operated).

Impacts of new conservation and generation resource development and operation are represented by estimates of air quality impacts and water consumption (for cooling) from the operation of new CTs and land use by all new generation resources. These estimates were developed by multiplying the emissions factors for new natural-gas fired CTs in table 4.3-1 by the amounts of new CT operations shown in table 4.4-15. Land use impacts were estimated by multiplying the land use requirements for each type of new generation resource shown in table 4.3-1 by the regional resource acquisitions shown in table 4.4-13.

Impacts of existing generating resource operation are of four types: air emissions from existing PNW CTs; air emissions and water use from existing regional coal resources; water use by existing regional nuclear plants (WNP-2); and operations and spill on the PNW hydroelectric system. CT and coal emissions shown in table 4.4-19 were developed by multiplying the amounts of existing regional CT and coal operations shown in table 4.4-15 by the emissions factors for existing CTs and coal shown in table 4.3-1. Spill is taken from table 4.4-15, and is based on BPA modeling of each alternative.

Impacts of power sales and purchases are represented by estimates of changes in emissions by CTs. It is assumed for purposes of analysis that secondary power sales from the PNW would occur during periods of high flows, when there is excess hydroelectric energy on the PNW system. It is likely that these secondary sales (shown in table 4.4-15) would displace thermal resources in California or the Inland Southwest. Power purchases (as shown in table 4.4-15, power purchases represent much smaller amounts) are assumed to be supported by thermal generation. The air emissions shown for power sales and purchases in table 4.4-19 were developed by subtracting secondary sales from power purchases and multiplying the net amount by the emissions factors for existing CTs shown in table 4.3-1. The negative numbers in table 4.4-19 reflect the fact that the analysis predicts that more CTs would be displaced (probably in California and the Inland Southwest), than would operate to support power purchases by the PNW.

Impacts of transmission development are represented by the amounts of land required for new right-of-way development. These numbers are derived by multiplying the amounts of new transmission predicted for each alternative (measured in kilometers of transmission lines of each voltage class) (table 4.4-16) by the coefficients for land use requirements for new transmission shown in table 4.3-1. It should be noted that the estimates of the land use requirements for new transmission facilities assume that new rights-of-way could be widened to accommodate new or higher-voltage lines; therefore, the land use estimates in table 4.3-1 may be higher than would actually occur.

Impacts from the operation of new transmission lines are difficult to predict; perhaps the chief impact of public concern, EMF, varies considerably by line configuration and line loadings. In addition, human exposure to EMF also depends on the location of the transmission facilities and the presence of other EMF sources. Because of the difficulty of predicting EMF for transmission facilities that have not yet been designed, impacts of transmission operations are not addressed here (see section 4.3.2 for general information about such impacts.)

Impacts associated with consumer behavior are represented by information on predicted changes in regional employment growth rates and the air quality impacts associated with fuel switching. Fuel switching air quality impacts were derived by multiplying the predictions of regional fuel switching (table 4.4-13) by the emissions factors for fuel switching shown in table 4.3-1. Fuel switching air emissions represent the emissions that result from combustion of natural gas in home water heaters and furnaces. It should be understood that the fuel switching also leads to a reduction in air emissions by reducing the amount of thermal generation to produced electricity. This positive effect of fuel switching is captured in the numbers reported for air emissions from new thermal generation in table 4.4-19. Those numbers would be substantially higher if fuel switching were not reducing the need for new generating resources by an amount reflecting the amount of fuel switching predicted for each alternative.

The key environmental impacts shown in table 4.4-19 are summarized in table 4.4-20 and figure 4.4-5 in terms of overall effects on air, land, water, and socioeconomics. The air entries in table 4.4-20 reflect the total of air quality impacts associated with the operation of aluminum DSIs, existing coal, existing and new CTs, fuel switching, extraregional sales (i.e., the displacement of CT operations), and power purchases (operations of CTs). The land use entry adds the land use impacts of new transmission and new generation. Water impacts are represented by the sum of cooling water requirements for aluminum DSIs, coal, new and existing CTs, existing nuclear (WNP-2), and power purchases (assumed to be CT operations); and the reduction of water requirements resulting from the displacement of CT operations by extraregional sales. Socioeconomic impacts are represented by predicted changes in regional employment growth rates (as noted above, no statistically significant differences are noted among the alternatives).

The final row of table 4.4-20 summarizes environmental externality costs of SO_X, NO_X, TSP, and $C0_2$ emissions from aluminum DSIs, existing coal, existing and new CTs, fuel switching, extraregional sales (i.e., the displacement of CT operations), and power purchases (operations of CTs), as shown in the top part of the same table. The environmental externality estimates are those BPA developed and published in 1991, inflated to 1995 dollars.

Economic Impacts

The economic analysis to predict regional employment change assumed a base case (Status Quo) that was described by Bonneville's Economic and Demographic Forecasts of the Pacific Northwest, completed in July 1993. These projections defined a most likely forecast for employment, population, and income for Idaho, Oregon, Washington, and western Montana, and defined the medium case forecasts used for final Rate Case analyses and incorporated into the 1995 Rate Case.

Potential economic effects (positive or negative) of the alternatives primarily are caused by changes to the rates charged for electricity to consumers, businesses, and industry. Rates trends of each of the alternatives are documented in section 4.4.3.1.

In Status Quo, economic performance in the Pacific Northwest is expected to continue to outpace the nation over the period 1993 to 2002. Total employment growth in the region is expected to average about 2.2 percent per year from 1993 to 1996 and about 1.9 percent per year from 1996 to 2002. Growth for the U.S. is expected to average 2.0 percent and 1.7 percent over the same periods.

Total employment in the region is expected to grow from about 4.1 million in 1993 to over 4.6 million in 1996 and exceed 5.2 million in 2002. Population is expected to grow from about 9.7 million in 1993 to about 10.2 million in 1996 and exceed 11.1 million by 2002. Relatively higher birth rates, solid economic conditions, and continuing in-migration from California will fuel the population growth.

These projections were based on medium-case forecasts of the U.S. and world economies and assumed, among other things, that there would be limited timber harvesting in the region, as well as continuing downswing at Boeing. It was also assumed that electricity rates in the region would grow at the pace defined by Bonneville's Power and Transmission Rate Projections for 1993 to 2014.

The regional economic projections assumed that the 1992 Resource Program would continue and that the resources to be built would follow the pattern described in that document. Much of the additional money raised by Bonneville through higher rates would be re-spent in the region for conservation, generation, transmission, and fish and wildlife expenditures. This re-spending provides economic stimulus to offset the relative costs of higher rates.

This forecast has a near-term range of uncertainty of about 2 percent. Over the longer term the range of uncertainty grows to roughly 8 percent. This uncertainty includes the typical effects of the business cycle, national factors, and structural assumptions for the region.

The economic impact analysis concluded that none of the alternatives would cause economic effects large enough to result in any statistically significant changes to the predicted regional employment growth rate of 1.9 percent over the period 1996-2002.

Table 4.4-20: Summary of Key Environmental Impacts of Alternatives[(a)] Under 1994-1998 Biological Opinion Hydro Operations

Effect	Unit	Status Quo	BPA Influence	Market Driven (Proposed Action)	Maximize Financial Returns	Minimal BPA	Short-Term Marketing
Air							
SO2	Tons	30,000	29,000	32,000	33,000	32,000	32,000
NOx	Tons	68,000	66,000	74,000	77,000	75,000	75,000
TSP	Tons	9,000	9,000	9,000	9,000	9,000	9,000
CO	Tons	166,000	165,000	166,000	167,000	167,000	165,000
CO2	Tons	32,000,000	31,000,000	33,000,000	34,000,000	35,000,000	34,000,000
Land							
Land Use	Hectares	15,000	16,000	15,000	15,000	15,000	15,000
Water							
Water Consumption	Cubic Meters	96,000,000	95,000,000	98,000,000	100,000,000	101,000,000	98,000,000
Socioeconomics							
Employment Change	Percent	1.9	NSSC	NSSC	NSSC	NSSC	NSSC
Environmental Externalities (b)	$ (1995)	$318,000,000	$308,000,000	$332,000,000	$344,000,000	$348,000,000	$339,000,000

NSSC = No statistically significant change.
(a) Summary of data in table 4.4-19.
(b) Monetized environmental externalities for SOx, NOx, TSP, and CO_2.

BPA Environmental Externality Estimates ($1995)		
	$/lb	**$/metric ton**
SOx	$0.9099	$1,651
NOx	$0.2890	$524
TSP	$0.5175	$939
CO_2	$0.0039	$7

Source: BPA final values for environmental costs, issued May 20, 1991, (escalated to $1995), except for CO_2 estimate, which is from draft values.

4.4.4 Market Responses and Impacts of Alternatives Under Detailed Fish Operating Plan (SOS 9a)

The following subsections describe Business Plan EIS alternative market responses and environmental impacts assuming that current hydroelectric operations are replaced by a strategy designed to increase flows and spill and to implement drawdown to aid anadromous fish migration. Characteristics of such a strategy (as developed by the System Operation Review and described in the Draft SOR EIS) are described in section 2.1.6 and at the end of section 4.3.4.3.

4.4.4.1 Business Effects of Detailed Fish Operating Plan Hydro Operation and Response Strategies

The Problem

Because of continuing concerns over the decline in certain populations of salmon, there are a number of proposals to change the operation of the Federal Columbia River Power System in an effort to improve the survival of these fish, particularly in the downstream migration of juvenile fish toward the ocean. Potential changes in operations could significantly alter BPA's business activities under the six alternatives addressed in this EIS. The following assessment of impacts is based on the assumption that the system would be operated according to System Operating Strategy 9a (SOS 9a) from the SOR process. SOS 9a operation is intended to represent an extreme case hydro operation, in terms of its effect on BPA's business planning and marketing. If the operation ultimately selected in other processes results in lesser changes in the system, the effects on BPA's business activities will be correspondingly smaller.

The Power Impact

The changes in the operation of the power system under SOS 9a and in the environmental impacts of those operations are described in sections 2.1.6 and 4.3.4. SOS 9a, in brief, provides for increased flows during the spring on both the Snake and mainstem Columbia rivers; it includes spill at all dams, with reservoir drawdowns at all Lower Snake River projects and John Day Dam (see figure 4.3-5 for locations of hydro projects). These changes are expected to reduce significantly the capability of Federal hydro projects to produce power, particularly in the fall. Because flows would be shifted from fall and winter into spring, monthly energy capability could be reduced by as much as 6,000 monthly aMW in September through December during average water years, and by 8,000 monthly aMW for the same period during the driest years. Drawdown and spill would reduce Federal generation by 4,400 monthly aMW in each month from May through July. Regional peaking capability would also be reduced by 6,000 to 10,000 MW from September through January.

The Financial Costs

The regional costs of these losses in hydro energy capability are estimated to average $300 to $600 million annually, and could be as much as $1 billion in the driest years. Capacity losses could cost the region from $100 to $175 million, although some of this loss could be offset by the peaking capability of resources that would replace energy losses, to the extent the energy was replaced by generating resources rather than by purchases. This generating capacity offset would be no more than about half of the capacity loss, because the largest monthly energy losses would be about half the magnitude of the capacity loss. Costs to BPA, assuming BPA ratepayers absorb 75 percent of these costs (in proportion to BPA's share of generation along the affected river reaches), would be $300 to $600 million annually.

The Environmental Impact

Regardless of how the impacts of the generation capability losses are distributed throughout the region, there are a limited number of ways to replace the lost capability: in the short term, purchases of power from generation inside and outside the region (most likely gas-fired CTs and/or existing coal generation), and in the longer term, new generation and conservation sources. Although a variety of new generation and conservation sources are potentially available (as described in section 4.3, Generic Environmental Impacts, and in more detail in BPA's *Resource Programs Final EIS*), it is likely that new generation will be dominated by gas-fired CT impacts. The environmental impacts of CTs would depend on the quantity developed; impacts of CTs per megawatt are presented in Table 4.3-1, Typical Environmental Impacts From Power Generation and Transmission.

To the extent that lost generating capacity is replaced by imports from outside the region, there is a possibility that the capacity of the high-voltage interties that link the PNW to the south and east might have to be increased. Impacts of new 500-kV transmission vary considerably according to the new lines' location; typical impacts and land use requirements of transmission are presented in section 4.3.2, Transmission Development and Operation, and in Table 4.3-1, Typical Environmental Impacts from Power Generation and Transmission. The potential for developing new transmission is limited by the costs, the availability of right-of-way for new lines, and environmental concerns about new transmission facilities. In addition, because new interregional interties would take years to construct, they could not be expected to provide new opportunities for energy imports to replace lost hydro capability until after the study year for this EIS.

The Impact on BPA

Under an SOS 9a operation, BPA's near-term response would be to purchase power to replace the lost hydro capability. If the costs of replacement power were not anticipated in the rates in effect at the time SOS 9a operations were implemented, BPA's revenues likely would not be sufficient to pay its entire financial obligation, including its full annual payment to the U.S. Treasury, except in unusually wet years. If rates could be adjusted in response to the additional costs of power purchases, the effect of the additional costs would be to increase BPA's power rates. Increases in BPA's rate would give customers greater incentives to purchase power from non-BPA suppliers. Over the long term, BPA would probably replace the lost hydro capability with a combination of CTs and power purchases.

With the increase in costs resulting from SOS 9a operation, BPA would have to adopt response strategies to stabilize its loads and revenues. Unless BPA made some adjustment in response to SOS 9a operations to balance its costs with its revenues, the succession of partial or missed Treasury payments that would follow could be expected to trigger political intervention to address the continuing shortfall in BPA's payments.

Types of response strategies that BPA could consider to adjust to an SOS 9a operation are addressed in section 2.5.

4.4.4.2 Responses and Impacts Compared to 1994-1998 Biological Opinion (SOS 2d) Hydro Operation

For all of the EIS alternatives, the principal effect of SOS 9a hydro operation is the increase in the costs BPA incurs to meet its power supply obligations. Alternatives vary in the opportunities available for paying these costs.

Status Quo

Market Responses

Because average PF rates under this alternative would be above the maximum sustainable revenue level, the additional costs of implementing SOS 9a operations could greatly accelerate the shift of historical BPA loads to non-BPA suppliers. The amount of utility load switching from BPA to other suppliers could double from the estimates given under current hydro operations; little if any DSI load could be expected to continue BPA service. BPA would retain its utility and DSI loads only for the time they required to make alternative supply arrangements. Unless there were a large increase in the demand for power in other regions, BPA would be unlikely to sell its surplus firm power except at prices well below those necessary to recover costs.

BPA would be faced with revenue shortfalls and would likely be unable to make scheduled Treasury payments consistently. It would also potentially be unable, under severe hydro conditions, to meet its other financial commitments, such as WPPSS bond payments and conservation incentive payments.

In the face of a crisis due to BPA's failure to meet its financial obligations, BPA's spending would likely be curtailed, either voluntarily or through the intervention of DOE, FERC, the Treasury, or other parties. Cost reduction opportunities that BPA would adopt under other alternatives would be available under Status Quo, except to the extent that opportunities were lost due to delay.

In such a financial crisis, cost cutting could be expected to go beyond cuts that would permit established programs to continue. Curtailed spending could include suspending or terminating BPA's involvement in its most costly programs, including power resource acquisitions, transmission system development, energy conservation, the residential exchange program, and fish and wildlife enhancement, and potentially changing statutes to reduce or end BPA's role in supporting those programs. As a result, for those activities which serve a commercial market, market demand would create opportunities for other entities to take on former BPA functions. Where BPA's activities were based on non-commercial purposes, such as fish and wildlife enhancement or support for energy conservation and renewable resources, achievement would be reduced unless those purposes received financial support from other sources, either to continue BPA's efforts or to establish new implementation mechanisms.

Ultimately, under any of the EIS alternatives, radical measures to resolve BPA's financial crisis could redefine BPA's role in the region to resemble the Minimal BPA alternative. BPA could be forced to sell off assets to raise short-term cash. BPA's current mission could be truncated to eliminate financial risks and non-revenue-producing activities or assets, leaving BPA in a caretaker function for the system as it exists at the point when the financial crisis comes to a head. As a consequence of this redefinition, BPA's most important business role would likely be to manage the transmission system and residual generating capabilities to serve the surviving participants in the competitive wholesale power market.

Environmental Impacts

Impacts of generation, either from new CT development or from operation of existing generation to deliver purchased power to BPA, would increase to supply BPA with power to replace lost firm hydro capability. Correspondingly, except for spill, generation impacts within and outside the PNW would be reduced during spring flow periods due to displacement of thermal generation with BPA hydro generation from SOS 9a flows.

Most loads moving away from BPA service would be served with new CTs. The large load shift away from BPA would accelerate CT development, with consequent impacts on air quality, water consumption, and land use. CT operations, and therefore impacts, could be expected to rely upon displacement of CT generation with BPA nonfirm energy to reduce operating costs during spring flow augmentation periods. BPA would sell as much of the firm surplus resulting from lost loads as practicable, either displacing operation or deferring development of alternative resources, primarily CTs.

Curtailment of BPA energy conservation activities and renewable resource acquisitions would replace the environmental impacts of those resource types with the impacts of CTs, except to the extent that customers implement conservation or develop renewable resources, either independently or at the direction of regulatory agencies.

Response Strategies

Treating the Status Quo alternative as the no-action alternative, response strategies would be limited to the historical responses of raising rates to cover revenue requirements, which, as noted, would be of little help, at least with respect to firm power rates.

BPA Influence

Market Responses

Although firm power rates under BPA Influence are lower than in the Status Quo, they would still approach the maximum sustainable revenue level, and thus there would be little opportunity to use firm power rate increases to pay the added costs resulting from SOS 9a operation. Independent of the effect of a BPA rate increase, the prospect of a large increase in BPA's revenue requirement would reinforce customers' inclination to shift load to non-BPA suppliers as soon as practicable.

As under the Status Quo alternative, although to a slightly lesser degree, BPA would face significant revenue shortfalls and potential inability to make scheduled Treasury payments reliably. Unless BPA and its customers and constituents could agree on steps to restore stability, outside parties might intervene (as described above for the Status Quo alternative) to impose limits on BPA costs and activities.

One of the major cost reduction opportunities would be conservation incentive programs, which continue at historical levels under the BPA Influence alternative, and therefore have potential for reductions. Another area of potential savings would be BPA renewable resource acquisitions, which would be higher under this alternative than all others. Renewable resources are predicted to cost substantially more than the market price for power. A third area would be fish and wildlife programs, if the fish and wildlife benefits of SOS 9a operation made some of the other direct BPA-funded fish and wildlife measures unnecessary. Unlike the Status Quo alternative, under BPA Influence, BPA would already have adopted many other cost-cutting measures, so that additional cost-cutting would likely depend on curtailment of planned BPA program activities. As with Status Quo, where BPA activities were curtailed, other market suppliers could be expected to step in to replace BPA's commercial activities, while non-commercial BPA activities would only be replaced by specific measures to compensate for a reduced BPA role.

As noted above for the Status Quo alternative, a radical solution to relieving the financial burdens placed on BPA by SOS 9a operations could be to limit BPA's activities to managing the existing transmission system and power resources, leaving competitive marketing and noncommercial activities to other entities. This result is probably less likely under BPA Influence than under Status Quo, but adverse developments in the wholesale power market could worsen BPA's condition to the point where changes in its statutory missions could become a credible strategy to achieve financial stability.

Environmental Impacts

As with the Status Quo alternative, impacts of thermal generation would be shifted away from high-flow periods and toward fall/winter low-flow periods according to the requirements of SOS 9a operation. Where the thermal plants are located would determine whether air quality would be improved or reduced by such seasonal shifts.

CTs would serve most of the electrical load shifting away from BPA. If BPA conservation spending was reduced so that conservation achievement declined, additional CT impacts would occur as CTs were operated to serve the load that otherwise would have been met with conservation.

Response Strategies

Raising firm power rates would provide little if any benefit in meeting the additional costs of an SOS 9a operation, because the average PF rate under the BPA Influence alternative would already be at about the level of BPA's maximum sustainable revenues. Firm power rate increases would not add revenue, and could actually reduce revenue by increasing BPA's load losses.

Because BPA would offer unbundled power products and services and seek to develop new product lines under the BPA Influence alternative, there would be opportunities to increase revenue in response to an SOS 9a operation that would not be available under the Status Quo alternative. In particular, BPA could charge higher prices for products based on hydro flexibility, to take fullest advantage of its large share of regional hydro generation and the higher costs of providing generation support from non-hydro facilities. It is unlikely that these marketing efforts would be able to cover more than a fraction of the additional costs of SOS 9a operation by 2002, although, depending on BPA's marketing success, they eventually might provide hundreds of millions of dollars in revenue.

Given that the BPA Influence alternative is oriented toward additional incentives or conditions that promote the goals of the Northwest Power Act, BPA might take steps under an SOS 9a operation to prevent customer loads from switching to other suppliers and therefore escaping the terms of BPA service that support the Act's goals. Specifically, BPA could implement a stranded investment charge, both to discourage customers from terminating BPA service, and to raise the maximum sustainable revenue level and increase BPA's revenues to better enable BPA to pay the additional costs of an SOS 9a operation. Although the continuing downward trend in the cost of non-BPA power could reduce the benefits, a stranded investment charge that increased the total cost of shifting load from BPA to other suppliers by 5 mills/kWh could provide BPA with enough revenue to pay most of the additional costs of SOS 9a operation.

BPA could meet some of the SOS 9a costs through cost cuts. With cost reductions and program changes like those in the Market-Driven alternative, significant savings (roughly half of the historical spending for conservation programs) could be obtained in BPA's energy conservation activities. As above, if operational changes under SOS 9a were effective in improving the survival of declining salmon runs, the direct costs to BPA for other fish and wildlife measures might be reduced. Other cost reductions would probably reduce BPA's ability to achieve program goals, and might require changes in the statutes that define BPA's missions.

Strategies to transfer BPA costs to other entities could also help BPA to adapt to the additional costs of SOS 9a operations. Credit for fish and wildlife expenditures under section 4(h)(10)(C) would be a high priority. In keeping with the emphasis in this alternative for promoting the goals of the Northwest Power Act, if other measures were not sufficient to meet the costs of SOS 9a operations, BPA and its customers and constituents would likely seek appropriations to allow BPA to continue its efforts to achieve the goals of the Act.

Market-Driven BPA

Market Responses

Estimated BPA rates under the Market-Driven alternative are somewhat below the maximum sustainable revenue level, so there might be some potential for additional revenue through increases in firm power rates. Rate increases would increase the amount of BPA customers' loads that would shift to other suppliers. Aside from the direct effect of a rate increase on BPA's loads, the addition of SOS 9a costs to BPA's financial obligations would reinforce customers' concerns about unpredictable BPA costs, and further increase their tendency to shift load away from BPA.

Because of the opportunity to maintain and potentially increase revenues from firm power sales, the potential for revenue shortfall would be less under the Market-Driven alternative than under the BPA Influence alternative, and the amount of the shortfall would also likely be less. However, a significant decline in the price of power in the wholesale market could reduce BPA's revenues below the amount necessary to pay all of its costs and lead to initiatives to limit BPA's activities, as described above for the Status Quo and BPA Influence alternatives.

The wide-ranging spending reductions already incorporated into this alternative would limit further opportunities for cost savings. The most prominent exception would be the potential that SOS 9a would be so effective in restoring fish runs that other BPA fish and wildlife spending could be reduced. Additional spending reductions would likely reduce achievement of BPA's program goals. If spending reductions were accomplished by cutting back on BPA's program responsibilities, achievement of current program goals would be reduced unless other entities filled in where BPA's activity decreased.

Environmental Impacts

Consistent with previous alternatives, the chief environmental impacts of the Market-Driven alternative under SOS 9a operations would be the impacts of resources or power purchases BPA arranged to replace lost firm hydro capability and the complementary spring displacement of thermal generation by hydro generation from higher spring flows under SOS 9a. CT impacts would increase from development and operation of additional CTs to serve loads moving away from BPA service. Impacts of generation also would increase if energy conservation achievement in the region were reduced due to cost cuts in conservation programs.

Response Strategies

BPA would raise firm power rates to the extent they would generate additional revenue to meet SOS 9a costs, and strive to increase revenues from sales of unbundled products and services, new product lines, and expanded extraregional and joint venture marketing. BPA would also make all practical operational arrangements to enhance marketing of generation available under SOS 9a operation, including storage and other adjustments in hydro operations. BPA would explore additional spending reductions that could be accomplished without jeopardizing achievement of its mandated missions.

Although a stranded investment charge could provide significant revenues to help cover SOS 9a costs, because of its coercive effect, it would be inconsistent with the concept of a Market-Driven BPA, and so BPA would not consider implementing it unless the utility industry generally adopted such charges, perhaps to temper the utilities' transition to a competitive power market.

FERC issued a Notice of Proposed Rulemaking (NOPR) on Open Access Transmission Services and Stranded Cost Recovery on March 29, 1995. This NOPR strongly supports the position that utilities have the opportunity for full recovery of the costs of stranded assets through the use of surcharges in transmission rates. While only a proposal, if this NOPR is adopted in its current form, it will provide BPA with additional support for implementation of a stranded investment charge for customers which chose to leave the system for lower-priced power from alternative suppliers or self-generation. BPA would not be in the position, as it would be now, as one of the few utilities in the United States imposing a stranded investment charge.

As with the other alternatives, BPA would take steps to transfer appropriate costs to other entities, particularly seeking credits under section 4(h)(10)(C) of the Northwest Power Act for fish and wildlife expenditures not attributable to the share of FCRPS costs allocated to power production. BPA might seek cost-sharing contributions from other participants or sponsors in its programs, and if appropriate, would pursue authorization to transfer program and financial responsibility to other agencies.

Maximize Financial Returns

Market Responses

BPA's rate under the Maximize Financial Returns alternative would be set deliberately at the maximum sustainable revenue level, independent of BPA's costs. Costs would be comparable to those of the Market-Driven alternative, and perhaps somewhat lower, so this alternative would generate substantial revenues above costs under current hydro operations. Expected SOS 9a costs would exceed even the maximum revenues under Maximize Financial Returns. BPA would not drive load away by increasing rates, recognizing that there would be no revenue benefit from a rate increase, but any confidence on the part of customers that BPA's rates would not increase would be undermined by the prospect that the additional costs above maximum revenues would render BPA insolvent as a business, and customer fears could lead them to shift load away from BPA service even if BPA did not act to increase firm power rates.

The revenues above costs that BPA would accrue under current hydro operations help BPA in paying the additional costs of SOS 9a operation, but would not be enough to cover all of the additional costs. BPA could avoid a revenue shortfall only through additional measures to balance revenues with costs. As with other alternatives, a decline in the price of competitors' power would worsen the situation and increase the likelihood of intervention to curtail BPA's activities.

Because the Maximize Financial Returns alternative is intended to represent a BPA that functions like a profit-making business, there would be few opportunities for additional cost reductions to help to balance revenues with SOS 9a costs. As with the Market-Driven alternative, savings in fish and wildlife spending might be possible if SOS 9a operations eliminated the need for some fish and wildlife measures.

Environmental Impacts

The impacts of the redistribution of hydro capability among the months of the year would be the same as under the other alternatives. Likewise, impacts of CT operation would increase to serve load shifting away from BPA service.

Response Strategies

BPA would not raise firm power rates under this alternative. There might be some increases in revenue available from increasing transmission rates. A stranded investment charge could help to increase revenues from loads moving off BPA service, and would increase the cost of non-BPA power and services, raising the maximum sustainable revenue level and enhancing BPA's ability to generate revenue to pay SOS 9a costs.

Based on the business interests of a BPA operated like a private profit-making enterprise, BPA would presumably have adopted most of the available cost-cutting measures under this alternative. Some cost savings could result from selling shares of new transmission capacity, or from increased Treasury borrowing or lowering the probability of making annual Treasury payments, but these steps would raise issues of debt ratio or credit worthiness that could make them undesirable for a revenue-maximizing business.

As with the previous alternatives, the 4(h)(10)(C) credit could make a significant contribution to BPA's revenues, and would be a high priority to mitigate the additional costs of SOS 9a operation. If other measures were not enough to pay any remaining SOS 9a costs, BPA would seek appropriations to prevent recurrent and unplanned failures to make scheduled Treasury payments.

Minimal BPA Marketing

Market Responses

Because BPA's obligations under the Minimal BPA alternative would be limited by the capability of its existing resources, and because SOS 9a operation would result in a reduction in the amount of power BPA would provide to its customers, BPA's customers' shares of BPA power would be reduced, and they would have to obtain replacement power from other sources. Public preference rights could put most of the reduction in available BPA firm power on the DSIs. (There are questions about how the seasonal shape of the lost hydro potential would fit with DSI loads.) In most cases, the replacement power would be supplied from CT generation.

In addition, as with the other alternatives, BPA's firm power price would increase to the maximum sustainable revenue level. As a result, some loads would shift away from BPA service. The effect of the increase in BPA's firm power rate would be to drive away some loads, leaving BPA with unmarketable requirements firm power that BPA would have to sell as firm surplus.

Environmental Impacts

The basic environmental impacts of the redistribution of hydro generation among the months of the year would be the same as for other alternatives. The most important difference under the Minimal BPA alternative would be that customers, rather than BPA, would make the choice of resources to replace lost hydro capability. BPA's choices would be influenced by the Council's Power Plan, whereas customers would be constrained mainly by least-cost planning or integrated resource planning requirements of state public utility commissions or resource siting authorities.

Response Strategies

BPA could raise power rates up to the maximum sustainable revenue level, as noted above. A stranded investment charge could provide significant amounts of additional direct revenue from loads moving off BPA service, and would raise the maximum sustainable revenue level, but it would imply more BPA intervention in customer choice than a "caretaker" role under this alternative would suggest.

Because BPA would have cut back on most of its program activities and would be a smaller organization than under the other alternatives, it is unlikely that significant additional spending reductions would be available under this alternative. As with other alternatives above, there might be some potential savings if some BPA-funded fish and wildlife program measures were rendered unnecessary by the implementation of SOS 9a operation.

As under all of the previous alternatives, BPA would almost certainly seek credit for the non-power share of its fish and wildlife expenditures under section 4(h)(10)(C) of the Northwest Power Act, and might seek appropriations for other SOS 9a costs if other strategies were not sufficient to balance revenues with costs.

Short-Term Marketing

Market Responses

Rates under the Short-Term Marketing alternative are about the same as those under the Market-Driven alternative; therefore, the rate and load effects would also be similar. Loads would decline with the increase in rates to the maximum sustainable revenue level, and SOS 9a costs would heighten customers' concerns about BPA costs.

As with the other alternatives, costs exceeding BPA’s revenues would create a potential for intervention to limit BPA’s activities, and could force BPA into decisions about priority among obligations to determine which would be paid.

Spending could be reduced if some fish and wildlife spending were rendered unnecessary, or if BPA’s program activities were curtailed. Other entities might take over discontinued BPA activities, depending on their potential business opportunities or funding support.

Environmental Impacts

Impacts would be essentially the same as those of the Market-Driven alternative.

Response Strategies

BPA would raise power rates to the maximum sustainable revenue level, and increase revenues from other activities to the extent feasible. The increased costs of SOS 9a operation might motivate BPA to expand its marketing beyond short-term marketing in order to increase revenue.

BPA would not implement a stranded investment charge under this alternative unless such a charge became an industry standard.

To help balance revenues with costs, BPA would implement any feasible spending reductions that were consistent with achieving its missions.

BPA would take advantage of any available sources of financial support, at a minimum seeking credit for fish and wildlife expenditures under section 4(h)(10)(C) of the Northwest Power Act, and likely including other prospects for cost-sharing, appropriations, or the transfer of financial and program obligations to other agencies.

4.4.5 Planning Uncertainties

The analysis of market responses under the alternatives presented above is based on a number of assumptions about conditions in the regional electric energy market. These assumptions generally describe conditions like those that the region has experienced in the past. There is considerable uncertainty about some of the conditions that affect BPA planning. Changes could occur regardless of BPA's actions as described in the alternatives. Because some of the changes could be significant, major issues of planning uncertainty are discussed below.

Where possible, the effects of these uncertainties are expressed in terms of the amount by which they change BPA's revenue requirement. The effect on BPA's rates can be estimated using the rule of thumb that every $100 million change in BPA's revenue requirement results in roughly a 1 mill/kWh change in the Priority Firm rate if the revenue is assumed to come from PF sales. Increases in BPA's PF rate typically result in load reductions among consumers due to price elasticity, and may induce utility and DSI customers to purchase non-BPA services, further reducing BPA's loads and resource needs. (Note that the demand elasticity of BPA’s wholesale power customers—electric utilities and large DSIs—is vastly different in magnitude, though not in motivation, from the more commonly considered elasticity of residential, commercial, and industrial power consumers.) Such reductions could either reduce BPA's resource acquisition costs, or increase the amounts of surplus power BPA would have available.

Table 4.4-21 compares the effects of the issues.

Table 4.4-21: Potential Effects of Planning Uncertainties on BPA Revenues, PF Rates, and Loads in 2002

Type of Planning Uncertainty	Potential Effect on BPA Annual Revenues ($M)	Potential Effect on BPA's PF Rate (mills/kWh)	Potential Effect on Forecasted BPA Loads (aMW)
Low Load Growth	-220	Reduce increases	-2,800
High Load Growth	+180	+1.5	+2,300
Revenue Financing at Borrowing Limit	Requirement +240	+2.4	-175
Repayment Reform	Requirement +300	+3	-225
Debt Refinancing	Requirement +30	+0.3	-25
Lost Hydro Firm Capability Due to Extended Drought	Requirement +20/100 aMW lost firm hydro	+0.2/100 aMW	-15/100 aMW
Aluminum Price	+70 to +220 at prices 70¢/lb to $1.00/lb	-0.7 to -2	+800 aMW (in DSI loads) at 70¢/lb or more
Carbon Tax or Increase in Natural Gas Price	Increased costs for CT generation	Increases due to purchases of CT generation	Reduce BPA load loss to customer CT generation

4.4.5.1 High or Low Load Growth

The alternatives are evaluated in terms of the medium load forecast as published in the 1995 Rate Case. Potential future regional loads could vary by several thousand average megawatts due to economic conditions, consumer fuel choices, or other influences on demand. If actual loads were to deviate from the medium forecast, resource needs and power sales might change significantly from the amounts shown above. Higher loads could present opportunities to market surplus resources, but whether BPA served those loads would depend on utilities' and perhaps consumers' choices of energy supplier. Lower loads would increase the surpluses BPA would need to market to recover resource costs. For a 1,000 aMW reduction from medium loads, BPA revenues would be reduced $80 million or more in 2002 due to the sale of firm power as nonfirm (assuming a PF rate of about 27 mills/kWh and an average nonfirm price of 18 mills/kWh). For increases in loads above the medium forecast, the effect would be the reverse, except to the extent that increases in loads were not served by BPA. The extremes of forecasted loads could increase or decrease BPA's revenues by over $300 million annually. Using the rule of thumb described above, extremes of loads could raise or lower BPA's PF rate by more than 3 mills/kWh, with corresponding effects on BPA's loads and resource needs.

An increase in the average PF rate would result in a response to price among consumers that would cause them to reduce loads. A rule of thumb for price elasticity of retail loads of BPA's utility customers is that a 1-percent increase in the PF rate results in a 0.3-percent reduction in loads. Using that rule, and rounding off a 1-mill increase in the PF rate to a 4-percent increase (from the current PF rate of about 27 mills), a 1-mill increase in BPA's rates would result in about a 1.2-percent reduction in BPA's utility loads, or about 75 aMW in 2003. (DSI loads are not assumed to respond the same as utility loads, due to particular conditions of PNW aluminum plants and the aluminum market, and their variable rate.)

4.4.5.2 Exhaustion of BPA Borrowing Authority

BPA currently finances its capital investments by borrowing from the Federal Treasury. The statutes that authorize BPA to use Treasury financing establish limits on the total amount that BPA may borrow. These limits are $1.25 billion for energy conservation, and $2.5 billion for power system facilities. Projected capital investments in the next several years would reach these borrowing limits. Once the limits were reached, BPA could obtain authorization for further Treasury borrowing, finance investments from other sources such as third parties, use revenues from the sale of BPA products and services to pay for capital investments without borrowing, or limit its capital expenditures so that annual BPA borrowing did not exceed annual authorization.

If BPA did not obtain authority for additional borrowing, and chose to finance capital programs from power revenues, the result would be a substantial increase in BPA's annual revenue requirement. Based on current estimated capital program levels (after including recent cost-cutting efforts), revenue financing for these programs after BPA reached the borrowing limit would increase BPA's annual revenue requirement, starting in 2001, by about $76 million, increasing in the out years.

Again using the rule of thumb described above, revenue financing could increase BPA's PF rate by over 2 mills/kWh by 2002, with corresponding effects on BPA's loads and resource needs.

4.4.5.3 Changes in Repayment of Federal Investment in the FCRPS: Repayment Acceleration or Debt Refinancing

One of BPA's major financial obligations is the repayment of the Federal investment in the Pacific Northwest power system. Over the past several years, there have been repeated proposals to accelerate or modify the terms for repayment of this debt. A related concept is refinancing the Federal debt on the power system.

Since the mid-1980s, each President's budget but one has included a proposal to restructure BPA's repayment of appropriated debt in order to address what some perceive as a taxpayer subsidy because of the low interest rates on some of the appropriations. The proposals have included increasing the interest rate on the debt and repaying the debt on a fixed amortization schedule over the remaining repayment period, rather than the flexible schedule now in use. Potential rate impacts have varied according to the particular proposal, but have tended to range between 10 and 15 percent, or in the range of $300 million in additional revenues per year.

In the fall of 1993, as part of Vice President Gore's initiative on reinventing government, the Clinton administration submitted legislation calling for BPA to buy out its outstanding repayment obligations on appropriations with debt that it would sell in the open market. The Congressional Budget Office (CBO) interpreted the legislation as adding to the Federal deficit because BPA's cost of debt in the open market was projected to be higher than Treasury's. Subsequently, BPA worked with its customers and constituents to develop Treasury-based buy-out options that would not increase the deficit, would be rate-neutral or near-rate-neutral, enable an equitable and predictable allocation of costs and benefits of buy-out to generation and transmission customers, and address subsidy criticisms.

In January 1995, Senator Hatfield introduced legislation that meets these objectives by allowing BPA to "reconstitute" its outstanding repayment obligations on appropriations by replacing them with new repayment obligations. Principal on the new repayment obligations would be set at the present value of BPA's debt service payment on appropriations under a term schedule, plus $100 million. The new principal would be assigned current market interest rates, and existing due dates for retiring the obligations would be retained. The proposal is designed not to increase the deficit over the FY 1995-1999 budget window, and to result in near-neutrality in rates for both generation and transmission. Preliminary estimates show BPA's revenue requirements increasing by roughly $30 million per year under this proposal.

4.4.5.4 Extended Drought

Abnormal climatic conditions, notably the El Niño phenomenon in the western Pacific Ocean, have been linked to several years of below-normal precipitation for the Pacific Northwest in the last decade. Continued drought could have adverse effects on power availability, because the Pacific Northwest electric power system has such a high percentage of hydro generation.

Regional electric energy planning has developed based on an accumulation of historical information covering more than 60 years of runoff data. This information is used to anticipate firm hydro power availability and nonfirm energy sales. Compared to geologic time periods, the amount of historical information about the

Pacific Northwest climate that is available to predict streamflow is very small. It is possible that the typical climate is drier, and therefore hydro runoff is less than the 60-year record indicates. Alternatively, it is possible that the climate of the Pacific Northwest is changing, due either to global warming or other changes such as long-term natural climatic cycles. If either of these hypotheses is correct, and the rainfall in the region continues to be less than historical averages, power availability and BPA's hydro-based power revenues would also decline.

The effect of an extended drought would be similar to the effect of the loss in firm hydro capability. The difference would be that, with chronic low runoff, the loss in firm capability would not be offset by nonfirm energy sales, because the flow itself would be less, rather than BPA having less flow available for firm energy generation. The monetary cost to BPA of an extended drought, per kWh lost, would be about three times that of the losses in firm hydro capability due to system operations changes, because there would be no offsetting nonfirm sales. For every 100 aMW of lost generation, the monetary effect on BPA, at 25 mills/kWh, would be over $20 million annually. The extent of the loss depends on how much flow would be reduced on the river system.

4.4.5.5 Change in Aluminum Price

In 1994, the aluminum industry purchased about one-fourth of the energy BPA sold. BPA's revenues and its operational relationship with aluminum plants are significantly affected by changes in the price of aluminum, partly due to the Variable Industrial Power (VI) rate which governs sales to those plants and which is tied to the U.S. transaction price for aluminum. During the late 1980s, high aluminum prices increased BPA's revenues under the VI rate. Recent depressed prices (due to increased world economic activity), continued operation of smelters with variable production costs during this period of low prices, and the sale of aluminum from plants in the former Soviet Union, have reduced BPA's revenues. These unpredictable changes add to uncertainty in BPA's aluminum DSI loads, because plants may shut down in response to adverse market conditions and cease buying power, and in BPA's revenues, both as the variable rate changes and as plants change operations.

Although the price of aluminum continues to be unpredictable, it is possible to estimate the effect of different aluminum prices on the operations and energy choices of Pacific Northwest plants. Recent prices have ranged between 75 and 85 cents per pound.

One measure of the effect of aluminum prices in relation to BPA rates is the "break-even" point, where the market price is enough to equal all production costs, including BPA power costs, without any profit. The break-even points for PNW aluminum smelters, when all 10 PNW smelters will operate, in relation to different levels of BPA rates, are as follows:

BPA Rate	Break-Even Aluminum Price
26 mills/kWh (current VI "plateau" rate)	70 cents
30 mills/kWh	73 cents
35 mills/kWh (a hypothetical CT cost)	77 cents
40 mills/kWh	80 cents

Since businesses need some profit margin to remain viable, the above figures do not necessarily indicate whether the smelters would actually operate. Considering that aluminum is a cyclical business, there should be enough profit margin to provide for market uncertainties and risks. Taking into account all the risks involved, the following points summarize expected responses of PNW smelters to power prices, whether from BPA or from other suppliers.

- At the expected long-term price averaging 80 cents per pound, all PNW smelters would remain operating with rates up to 29 mills/kWh.
- At 30 mills/kWh, the least-profitable plants probably would cease operations.
- At 35 mills/kWh, half the smelters probably would not operate.

- At 40 mills/kWh, the remaining half probably would cease operations.

There are other factors which may alter these general conclusions. For example, the new clean air environmental standards which go into effect in 1997 likely will add to operating costs and raise the break-even price or lower the power rate levels that may lead to plant shutdowns.

Under the existing variable rate, changes in the price of aluminum affect BPA's revenues. The current variable rate, based on the price of aluminum, is 26 mills/kWh. This adds about $73 million to BPA's revenues from current aluminum industry loads (about 2,100 aMW), as compared to the DSI rate when the draft BP EIS was prepared. Recent high prices (75 to 85 cents) could also encourage PNW plants to come up to full loads (about 2,900 aMW), adding another $70 million to BPA's revenues (comparing sales at the variable price to an average nonfirm price of 16 mills/kWh). If the price of aluminum stays above 94 cents per pound, the variable rate would increase still further, reaching its maximum of 32 mills/kWh at $1.02 per pound, which, at full capacity for PNW plants, would give BPA an additional $150 million in revenues. (The aluminum price levels that govern BPA rates under the VI rate schedule will be adjusted slightly in July 1995.)

Changes in aluminum prices affect BPA's revenues under the VI rate. Changes in the amount of aluminum DSI load operating affect BPA's resource needs, and the environmental impacts of both resource operations and smelter operations.

4.4.5.6 Changes in Energy Resource Technology

The conclusions in this EIS about the relative amounts of resource development among the alternatives are founded on current information about the relative costs of different energy resource technologies. As the re-emergence of natural gas generation as a competitive resource in recent years demonstrates, the market for electric energy can change rapidly as prices change and technologies evolve. A number of potential developments could significantly change the Pacific Northwest electric energy market from the conclusions that are described here.

For example, CT technology could continue to increase fuel efficiency, size, and environmental performance, and therefore the price competitiveness of CTs in relation to other resources. Fuel cells are another technology that appears to be on the brink of commercialization. Fuel cells could conceivably be available in sizes which could serve individual communities or industries, as “distributed generation” which could change the market for transmission services from long-distance delivery of wholesale power toward delivery of backup service and reserves based on load or outage diversity. Widespread commercialization of photovoltaic cells, producing supplemental energy during daylight hours, could alter system load shapes, reducing peak demands and increasing the effective use of existing transmission and generation.

The effects of these developments are difficult to quantify, but they reinforce the view that long-term planning must be flexible enough to accommodate new developments. One major risk is the potential that BPA or other regional utilities will have unmarketable surplus power due to the proliferation of generation that supplies end-use loads and displaces BPA or utility generation. Costs of stranded investments in resources would compound the challenge of maintaining competitive pricing.

4.4.5.7 Changes in Environmental Laws and Regulations

Carbon Tax

Relative costs of energy resources can be profoundly affected by changes in environmental laws and regulations. One example is the concept of a “carbon tax” on fossil fuels used to power generating facilities. Such a tax would be based on those facilities' potential to emit carbon dioxide or other “greenhouse” gases. A carbon tax would have to be very large (sufficient to raise the levelized resource cost to about 50 mills/kWh, a tax of about 13 mills/kWh) to displace natural gas-fired CTs from their dominance among resources available to provide additional power to the PNW. However, any carbon tax would add to the cost of carbon-based generation, and would affect the price at which BPA's customers would be motivated to purchase from other suppliers rather than BPA. The result would be to reduce losses of BPA's loads to independently developed gas-fired generation and reduce fossil-fueled resource development by other suppliers across all of the alternatives addressed in this EIS. To the extent BPA acquired gas-fired generation to supply firm loads, BPA's costs would also increase as a result of a carbon tax.

Curtailment of Natural Gas Supply

Another possibility is the potential for restrictions on the export of natural gas from Canada to the United States. If such restrictions were adopted, the potential for natural gas-fired generation could be reduced dramatically. The effect would be to shift resource development to other resources with higher costs, and, as above, to increase the BPA rate which would cause BPA's customers to purchase generation from other suppliers. One possibility would be that coal gasification technology might develop to the point where it could supply fuel for CTs. If so, the impacts of generation fueled by coal gasification would include the impacts of coal mining and the gasification process.

EMF Regulations

Regulations concerning EMF could have a significant effect on BPA's transmission development and operations. High-voltage transmission lines, such as those on BPA's transmission system, generate EMF when power is flowing over the lines. There is widespread interest in determining whether EMF exposure results in adverse effects on human health. Some of this interest has led to legislative or regulatory proposals to establish EMF standards. To date, six states (OR, FL, MN, NJ, NY, and MT) have established electric field standards, and two of those (FL and NY) have established magnetic field standards. Other proposals for standards have been raised at the Federal, state, and local levels. BPA has adopted guidelines addressing its practices with regard to EMF in its "1995 Guidelines on Electric and Magnetic Fields." (Electric Power Lines Questions and Answers on Research into Health Effects, in press, publication June 1995.)

So far, regulations on EMF have not required significant changes in BPA's transmission operations or development. However, if serious health effects were demonstrated, standards could potentially become stringent enough to limit BPA's use of its existing transmission facilities, or prevent development of new transmission lines in populous areas. Constraints on transmission capacity arising from EMF regulations could limit the amounts of power BPA could deliver, which could create problems meeting load during peak demand periods. Long-term limitations could cause power outages at load centers dependent on distant generators, and could stimulate local demand management or generation development.

Stricter Regulations on Emissions

Tightening regulations on releases of pollutants into air, water, or land predictably increase the costs of power generation and industrial operations which produce such pollutants. For power generating resources, such changes, like the carbon tax, would increase the costs of some resources relative to resources which did not produce the same types of pollutants, and could alter BPA's and its customers' decisions about resource acquisitions under least-cost resource plans. For industrial operations, increased costs for pollution control measures could add to the effect of differences in power costs on economic decisions, such as whether to expand production, continue operation, or close. In the Pacific Northwest, industries which might be affected by such changes in laws include aluminum, chlor\alkali, wood products, pulp and paper, and food products.

4.4.5.8 Changes in the Price of Natural Gas

Most current proposals for the development of new electric power resources are based on the expectation that abundant supplies of low-cost natural gas will be available over the long term. If the price of natural gas increased, proposed new gas-fired generating resources might be less appealing in comparison to other types of resources, such as cogeneration, energy conservation or DSM, and renewable resources. Events which could lead to an increase in the price of natural gas would include natural disasters in regions supplying the gas, new taxes (such as the carbon tax discussed above), or the discovery of new costs or hazards associated with producing gas. As was noted above, based on current estimates of the relative costs of different energy resources for the PNW, the total increase in price, including production costs and taxes, would have to raise the cost of natural gas resources to 50 mills/kWh or more to substantially displace natural gas as the dominant type of resource for new electrical generation. As stated earlier, the spot market price of gas was in the $1.00 to $1.50/MMBtu throughout the winter of 1994-95. For the latest generation of CTs, these gas prices translate into an operating cost of between 8 and 12 mills/kWh. If gas prices continue to fall, or stay at current levels, this could place additional pressure on utilities in the region to shut down high operating cost base-load thermal power plants. Plants at the greatest risk of closing are nuclear and coal plants with high operating costs.

Increases in natural gas costs below the level that would change the resource mix for the PNW would affect BPA, though, by increasing the cost at which customers would choose to purchase from other suppliers rather than from BPA. Higher gas prices would tend to increase BPA loads and shift resource acquisitions to BPA from other suppliers.

4.5 Market Responses and Impacts of Modules

The sections that follow describe the market responses and environmental impacts of the policy modules described in chapter 2. Table 4.5-1 presents a summary of the impacts of the modules as they apply in each alternative.

Table 4.5-1: Market Responses and Environmental Impacts of Modules by Alternative

Module	Status Quo	BPA Influence	Market-Driven BPA	Maximize BPA's Financial Returns	Minimal BPA	Short-Term Marketing
Fish and Wildlife						
Status Quo (FW-1)	Intrinsic to alternative. Undefined BPA role/uncertain cost control could encourage BPA customers to seek other power suppliers, possibly leading to increased thermal generation impacts.	Not applicable.	Not applicable.	Not applicable.	Not applicable.	Not applicable.
BPA-Proposed Fish and Wildlife Reinvention (FW-2)	Not applicable.	Intrinsic to alternative. Increased potential to predict/control costs; less potential for load loss.	Intrinsic to alternative; effect same as in BPA Influence alternative.	Same as in BPA Influence alternative.	Same as in BPA Influence alternative.	Intrinsic to alternative; effect same as in BPA Influence alternative.
Lump-Sum Transfer (FW-3)	Not applicable.	Impacts probably similar to those of proposed Fish and Wildlife Reinvention.	Same as in BPA Influence alternative.	Intrinsic to alternative; effect same as in BPA Influence alternative.	Intrinsic to alternative; effect same as in BPA Influence alternative.	Same as in BPA Influence alternative.
Rate Design						
Seasonal Rates—Three Periods (RD-1)	Not applicable.	More loads placed on BPA in spring/ summer; more reliance by BPA customers on purchased (thermal) power in fall/winter, with related thermal power impacts.	Intrinsic to alternative; impacts as described for BPA Influence alternative.	Impacts as described for BPA Influence alternative.	Impacts as described for BPA Influence alternative.	Impacts as described for BPA Influence alternative.

Table 4.5-1 (continued): Market Responses and Environmental Impacts of Modules by Alternative

Module	Status Quo	BPA Influence	Market-Driven BPA	Maximize BPA's Financial Returns	Minimal BPA	Short-Term Marketing
Rate Design (continued)						
Streamflow Seasonal Rates—Real Time (RD-2)	Not applicable.	BPA load loss and increased use of thermal generation from other sources with related thermal power impacts.	Impacts as described for BPA Influence alternative.	Impacts as described for BPA Influence alternative.	Impacts as described for BPA Influence alternative.	Impacts as described for BPA Influence alternative.
Streamflow Seasonal Rates—Historical (RD-3)	Not applicable.	Intrinsic to alternative: more loads placed on BPA in spring/summer; more reliance by BPA customers on purchased (thermal) power in fall/winter, with related thermal power impacts.	Impacts as described for BPA Influence alternative.	Impacts as described for BPA Influence alternative.	Impacts as described for BPA Influence alternative.	Impacts as described for BPA Influence alternative.
Eliminate Irrigation Discount (RD-4)	Not applicable.	Intrinsic to alternative; loss of some irrigation load; less irrigated agriculture, less irrigation water use; some farm losses.	Intrinsic to alternative; effects similar to impacts described for BPA Influence alternative.	Intrinsic to alternative; effects similar to impacts described for BPA Influence alternative.	Similar to impacts described for BPA Influence alternative.	Intrinsic to alternative; effects similar to impacts described for BPA Influence alternative.
Variable Industrial Rate (RD-5)	Intrinsic to alternative; under certain market conditions, could stabilize DSI load on BPA, lead to less resource development by other suppliers.	Similar to effect in Status Quo.	Similar to effect in Status Quo.	Similar to effect in Status Quo.	Similar to effect in Status Quo.	Similar to effect in Status Quo.

Table 4.5-1 (continued): Market Responses and Environmental Impacts of Modules by Alternative

Module	Status Quo	BPA Influence	Market-Driven BPA	Maximize BPA's Financial Returns	Minimal BPA	Short-Term Marketing
Rate Design (continued)						
Load-Based Tier 1 (RD-6)	Not applicable.	Less likelihood that winter-peaking utilities would turn to sources of power other than BPA; perhaps less likelihood of CT development and operation.	Intrinsic to alternative; impacts as described for BPA Influence alternative.	Similar to impacts described for BPA Influence alternative.	Not applicable.	Similar to impacts described for BPA Influence alternative.
Resource-Based Tier 1 (RD-7)	Not applicable.	Intrinsic to this alternative; more likelihood that winter-peaking utilities would turn to sources of power other than BPA; perhaps more likelihood of CT development and operation.	Impacts as described for BPA Influence alternative.	Impacts as described for BPA Influence alternative.	Not applicable.	Impacts as described for BPA Influence alternative.
Market-Based Tier 1 (RD-8)	Not applicable.	Impacts probably mid-way between Load- and Resource-Based Tier 1 modules.	Impacts as described for BPA Influence alternative.	Not applicable.	Not applicable.	Intrinsic to alternative; impacts as described for BPA Influence alternative.
Direct Service Industries						
Renew Existing Firm Contracts (DSI-1)	Intrinsic to alternative; assumed to cause some load loss in this alternative.	Increase BPA DSI load; increase revenue and reduce rates slightly; reduce new thermal generation by other entities; increase existing thermal generation.	Decrease BPA DSI load; increase in-lieu deliveries by same amount; displace existing thermal generation.	Same as in Market-Driven BPA alternative.	Not applicable.	Not applicable.

Table 4.5-1 (continued): Market Responses and Environmental Impacts of Modules by Alternative

Module	Status Quo	BPA Influence	Market-Driven BPA	Maximize BPA's Financial Returns	Minimal BPA	Short-Term Marketing
Direct Service Industries (continued)						
Firm DSI Power in Spring Only (DSI-2)	Not applicable.	Intrinsic to alternative; leads to loss of almost one-half of DSI load; increased new thermal generation by other entities.	Substantial loss of BPA DSI load partially replaced by increased in-lieu deliveries; increased cost and rate pressure; increased new thermal generation by other entities.	Approximately the same as under Market-Driven BPA alternative.	Similar to effect in Market-Driven BPA alternative but smaller in scale.	Similar to effect in Market-Driven BPA alternative but smaller in scale.
Declining Firm Service (DSI-3)	Not applicable.	BPA regains some DSI loads in the short term, increasing BPA revenues and reducing rates slightly.	Intrinsic to this alternative; leads to some increase in BPA DSI load in short term.	Probably little effect on BPA DSI loads in this alternative.	Intrinsic to alternative; similar to effect shown in Market-Driven BPA alternative.	Intrinsic to alternative; similar to effect shown in Market-Driven BPA alternative.
No New Firm DSI Power Sales Contracts (DSI-4)	Not applicable.	Loss of all BPA DSI firm load; substantial loss of revenue and increase in BPA rates; increase new thermal generation by other entities; displace existing thermal generation.	Same as in BPA Influence alternative (but greater magnitude).	Same as in BPA Influence alternative (but greater magnitude).	Intrinsic to alternative; impacts probably comparable to effects in Market-Driven BPA alternative.	Intrinsic to alternative; impacts probably comparable to effects in Market-Driven BPA alternative.
100-Percent Firm Service (DSI-5)	Not applicable.	Increase BPA DSI loads; increased revenue; reduce BPA rates slightly; less development of new thermal generation by other entities; more existing thermal generation.	Little effect on BPA DSI loads and revenues in short term; sustains higher DSI loads on BPA in long term.	Intrinsic to alternative; increases BPA DSI loads.	Not applicable.	Increase in BPA DSI loads, but little effect on BPA revenues.

Table 4.5-1 (continued): Market Responses and Environmental Impacts of Modules by Alternative

Module	Status Quo	BPA Influence	Market-Driven BPA	Maximize BPA's Financial Returns	Minimal BPA	Short-Term Marketing
Conservation/Renewable Resources						
"Fully Funded" Conservation (CR-1)	Intrinsic to alternative.	Intrinsic to alternative.	Increase BPA conservation by 140 aMW, regional conservation by 30 aMW; increase BPA rates; small reduction in environmental impacts of thermal generation.	Increase BPA conservation by 140 aMW, regional conservation by 230 aMW; increase BPA rates slightly; small reduction in environmental impacts of thermal generation.	Not applicable.	Increase BPA conservation by 250 aMW, regional conservation by 140 aMW; increase BPA rates; small reduction in environmental impacts of thermal generation.
Renewable Resource Incentives (CR-2)	Not applicable.	Intrinsic to alternative; probably has little effect on renewable resource acquisition.	Probably would have little effect.	Probably would have little effect.	Not applicable.	Probably would have little effect.
Maximize Renewable Resource Acquisitions (CR-3)	Not applicable.	Intrinsic to alternative; BPA would acquire 300 aMW additional wind and geothermal; BPA would try to sell resulting surplus power but would increase rates; small decrease in thermal generation impacts and increase in land use impacts.	BPA would acquire 300 aMW additional wind and geothermal; BPA would try to sell resulting surplus power but would increase rates; small decrease in thermal generation impacts and increase in land use impacts.	Comparable to Market-Driven alternative.	Not applicable.	BPA would acquire 380 aMW additional wind and geothermal. BPA would try to sell resulting surplus power, but would increase rates; small decrease in thermal generation impacts and increase in land use impacts.
"Green" Firm Power (CR-4)	Not applicable.	Intrinsic to alternative; BPA would acquire up to 80 aMW of wind and geothermal; would increase purchasers' average retail rates somewhat; slight decrease in thermal generation impacts and increase in land use impact.	Intrinsic to alternative; effect same as in BPA Influence alternative.	Intrinsic to alternative; effect same as in BPA Influence alternative.	Not applicable.	Same as in BPA Influence alternative.

4.5.1 Fish and Wildlife

There are three sets of issues regarding BPA's fish and wildlife program administration, related to its choices about 1) the level of responsibility and accountability BPA asserts for how program funds are spent; 2) how the agency attempts to control its fish and wildlife costs; and 3) who administers the program. The three modules developed to respond to the issues assume that the issues are inter-related; that is, that a particular level of responsibility and accountability for results may imply a particular administrative role.

Any of the fish and wildlife modules can be applied to any alternative, except the Status Quo alternative, which, as the no-action alternative, does not contemplate any new policies. All the modules are expected to implement the Council's F&W Program, the ESA Recovery Plan, and other mandated actions. At issue is not whether BPA will fulfill these responsibilities, but how it will be done and how the choices affect its ability to control its costs.

BPA cannot predict a hard and fast "x action leads to y consequence" of its fish and wildlife administrative choices. The analysis assumes the following:

- If BPA cannot control its costs, including fish and wildlife costs, it must raise rates. Raising rates motivates customers to buy from other suppliers rather than from BPA.
- If BPA loses a significant share of its firm load, its fixed costs will be spread among fewer customers, leading to rate increases. At some point, further rate increases will not increase revenue due to load losses. This is the maximum sustainable revenue level.
- If BPA cannot pay its full costs from maximum revenues, either some BPA activities will have to be curtailed, or BPA will have to receive additional funds or revenues to supplement power sales revenues.
- The amount of BPA load shifting to other suppliers could affect the development of conservation and generation resources in the region. To the extent customers move load away from BPA, such development would shift toward the resource choices of non-BPA suppliers and could also increase the need for transmission facilities.

This scenario assumes that customer responses are determined only by projected rates based on current estimates of BPA's costs. A complicating factor is that customers are considering suppliers other than BPA because they perceive that fish and wildlife costs are unpredictable, and they fear that, if they maintain their contracts with BPA, they will be subject to unknown additional costs in the future. They expect that actual BPA costs will be unpredictably higher than estimates. They are searching for alternative suppliers that will not be subject to the cost uncertainties that accompany BPA's fish and wildlife mission.

For BPA's competitiveness, market responses to how it administers its fish and wildlife responsibilities depend on the following:

- How the modules contribute to BPA's ability to control its costs
- How the modules improve customers' perception of BPA's ability to control costs.

Environmental impacts would vary with customer decisions to continue to use BPA to supply power or to find other suppliers. To the extent they stay with BPA, BPA's resource development choices would be maintained and impacts primarily would be those related to hydropower operations and planned new BPA resources (see section 4.3.4). If BPA customers were to shift to other suppliers, impacts that resulted would be those of other resources, predominantly CTs that the non-BPA suppliers would develop to serve their loads.

Contrary to implications in the initial Draft EIS, BPA has concluded that there is little evidence to support the conclusion that one particular administrative strategy will achieve greater or lesser improvements fish and wildlife populations compared with another. This analysis does not debate which measures to fund—those decisions are made as part of the Council's F&W Program development, the NMFS Recovery Plan, and as a result of other Federal agency and court decisions. Nor can this analysis claim that one entity in the region is more capable than another to achieve fish and wildlife improvements. As a consequence, BPA cannot predict any difference in environmental impacts to fish and wildlife from these modules. Any consequences would be indirect: if the worst case scenario were to occur and BPA had to curtail some activities, less money would be available for fish and wildlife measures, and it is unclear whether another entity would fill the funding gap. If replacement funding were not available, the region's ability to achieve its fish and wildlife goals could be impaired.

4.5.1.1 Status Quo (FW-1)

If BPA were to continue its current fish and wildlife administrative policies, the likelihood is high that its fish and wildlife costs would remain unstable and unpredictable, because it would not be comprehensively and systematically consulting with other regional entities to define and limit the size of its financial obligation for fish and wildlife enhancement and mitigation. BPA would not have a clearly defined set of criteria nor a regionally accepted role to help set funding priorities. Its fish and wildlife costs could be controlled more by entities whose responsibilities are focused on only one aspect of BPA's role—its role in regional fish and wildlife enhancement—rather than on its multiple roles, including assuring the region an adequate, economical, efficient and reliable power supply.

With the scope of BPA's responsibility and accountability remaining undefined, and with its control over its costs uncertain, some of BPA's customers would begin to act on their need for predictability of their power supply and its costs, and would switch to other suppliers. Depending on the number and size of customers who left BPA, impacts of CTs and other thermal resources might be greater than if customers remained with BPA and its hydropower. Under the worst-case scenario, fish and wildlife could be indirectly affected if BPA's revenues could no longer support funding all necessary fish and wildlife measures.

4.5.1.2 BPA-Proposed Fish and Wildlife Reinvention (FW-2)

Under this module, BPA might exert some additional control over its fish and wildlife costs, although probably not full control. With a recognized responsibility to administer funds, to consult on funding priorities and to monitor project success as input to continued funding decisions, BPA could more systematically assert influence on how ratepayer money is spent than under the Status Quo (Accountability Level I, figure 2.4-4). Agreements on base-level funding could substantially increase the predictability and stability of fish and wildlife costs, which could have the effect of increasing customer confidence that BPA rates would stay competitive, while at the same time assuring an adequate longer-term funding level for mitigation and enhancement. Tying additional funding for fish and wildlife measures to BPA's revenue success could provide for long-term support for fish and wildlife financed by trust fund earnings.

With emphasis in the fish and wildlife program on results, customers could be more confident of BPA's future fish and wildlife costs, and would have less incentive to shift load to other suppliers. If so, generation impacts would more closely follow BPA's resource acquisition choices.

The risk exists, however, that costs would increase, even with controls as described. If mitigation measures continued to show poor results and fish populations continue to decline, BPA and the fisheries interests could conclude that more spending is necessary, despite prior agreements. Then market responses and impacts could be similar to those described for Status Quo, unless BPA's financial obligation were limited, or other funds were made available to support additional actions to enhance fish survival.

4.5.1.3 Lump-Sum Transfer (FW-3)

The potential for control of BPA's fish and wildlife costs could be similar in this module to that of the proposed fish and wildlife reinvention (FW-2). The chief difference between the two modules is that, with a lump-sum transfer (assuming it could be accomplished legally), BPA would not be held accountable for project results because it would transfer its role in setting funding priorities and in monitoring to other entities (Accountability Level III, figure 2.4-4). Without BPA's involvement, some BPA customers might have slightly less confidence that ratepayer funds were being spent effectively (although there is no evidence to suggest they would not be); however, market responses of customers would probably depend primarily on the module's success in predicting and containing costs. BPA's financial responsibility would be defined in a multi-year agreement, as in the proposal, which could provide cost stability; however, the risk, as in the proposal, exists that lack of results could put pressure on BPA to increase funding levels despite prior agreements.

Impacts would be similar to those described for the proposed fish and wildlife module (FW-2).

4.5.2 Rate Design

This EIS addresses eight policy modules concerning rate design. Three address different ways to vary rates over the seasons of the year. Two address rate features directed at specific types of consumers: discounts to irrigators, and the variable rate to aluminum DSIs. The last three are different approaches to tiered rates.

4.5.2.1 Seasonal Rates - Three Periods (RD-1)

Module Description

In this module, BPA would design its power rates for utility customers to incorporate three separate rate periods or seasons of 3 to 5 months each. The goal of this rate design would be to achieve a closer linkage between BPA's wholesale rates and the price of power on the open market. Priority Firm, Industrial Firm and the New Resource rates would be seasonalized in this manner. Generally, rates would be highest in the winter when loads and power costs are high, low during the spring flow augmentation, and somewhere in between during the rest of the year. The differential between winter and spring rates could be as much as 15 mills/kWh.

Effect of Module on Alternatives

In general, the closer BPA's rates are to the market price of power, the more accurate the price signal sent to BPA's customers. By responding to market price signals, consumers can make more efficient use of electric generation and transmission resources. However, the effect of changes in rate structure can be overshadowed by changes in methods used to allocate costs among BPA's customer classes and between high and low load-factor customers.

Depending on the degree of seasonal differentiation in rates, BPA could be at risk of losing load from the generating public utilities and DSIs during the high-rate periods. In that case, these customers might increasingly rely on purchases during the winter months (probably supported by regional or extraregional thermal generation), and place more of their load on BPA in spring and summer months.

This module is evaluated as a variant to the BPA Influence, Minimal BPA, Short-Term Marketing, and Maximize Financial Returns alternatives; it is intrinsic to the Market-Driven alternative. Impacts of this module would be the same in kind among all alternatives to which it applies: customers would be likely to place more of their load on BPA during the low-rate period (spring and summer), and less during the higher-rate periods. During periods when they do not place load on BPA, these customers are likely to rely on power purchases, probably supported by existing thermal generation or CTs. The extent to which customers place more load onto BPA in low-rate periods and take load off BPA in high-rate periods would depend on the extent to which rates vary by period compared to the rates for alternative power supplies during those same periods.

Environmental Impacts

The operations of the hydroelectric system are being evaluated and determined through the System Operation Review (SOR) process, which will determine operational constraints for Federal hydro projects. Therefore, seasonal rates would have no impact on hydro operations; rather, they might help BPA shape its loads more closely to the capabilities of the hydroelectric system that result from the SOR process.

The primary environmental impact would stem from utility and DSI decisions about whether to place load on BPA given the seasonal rates. As noted above, it is possible that seasonal rates would result in more load placed on BPA in the spring when the seasonal rate is lowest, and less load in the winter when the rate would be higher. This could result in increased reliance on power purchases to meet utilities' and DSIs' peak winter needs. Power purchases are most likely to be supported by existing or new thermal generation (primarily CTs). Increased operation of CTs would lead to increases in NOx, SO2, CO, and CO2 emissions, water use, and land use impacts (identified on a per-megawatt basis in Table 4.3-1, Typical Environmental Impacts From Power Generation and Transmission).

4.5.2.2 Streamflow Seasonal Rates - Real Time (RD-2)

Module Description

BPA received several comments suggesting that linking power prices to streamflows would help to match BPA's loads to the capability of hydro generation. The advocates of streamflow rates suggested that they could be used to reflect the availability (or scarcity) of water by tying rates to existing hydrological conditions as they develop during the operating year. The rate structure evaluated for this module would have BPA rates changing monthly, based on projected streamflows. Projected rates would be developed and published by July 1 of each year for the upcoming 12 months. Each month, the streamflow would be re-estimated for the next month and all remaining months of the year, revising the rates accordingly. For BPA's firm power customers only, a balancing account would capture any over/under collections due to streamflow variances from projected flows. When hydropower generation is scarce due to low streamflows, rates would be higher; rates would be lower when hydropower generation is plentiful due to high streamflows.

Effects of Module on Alternatives

For a hydro-based power system like BPA's, water availability is a major, but not the only, driver of power costs. The recent completion of the Third AC Intertie has increased the PNW/PSW transfer capability to almost 8,000 MW. This increase, combined with the development of Regional Transmission Groups (RTGs) and the gradual reduction in barriers to transmission access, has helped create a vibrant west-coast market for electricity. The amount of runoff is no longer the prime determinant of west-coast power prices. Other major drivers of power costs are temperature, the economy, oil and gas prices, thermal generation availability, intertie availability and the demand for electricity.

While streamflows are an important determinant of the price of power in the PNW, basing the price of electricity solely on the level of streamflows would not fully reflect how the price of electricity is set in the wholesale market. Under real-time streamflow pricing, there could be long periods of time when BPA's streamflow rate and the wholesale market price of electricity would be different. In the short term, marketing and extraregional customers would do some "reshaping" of their own resources and modify purchases to respond to streamflow rates and to any disparity between streamflow rates and the market price of electricity. Non-marketing customers do not have the same flexibility; the resulting load changes would be small, but could lead to significant load loss to other utilities or self-generation if customers chose the greater certainty of power pricing from other resources. Because streamflows are volatile, this rate would create greater pricing volatility and uncertainty for BPA customers than rates fixed for specified periods of time.

For example, if the PNW experienced an abnormally wet year, a streamflow-based pricing methodology would set the price of electricity low to signal the low "cost" of water. If this occurred during an abnormally cold winter, an event such as the loss of a portion of the Intertie capacity or a shutdown of one or more large thermal resources could result in BPA seriously under-pricing its power. Under this scenario, demand for electricity would be very high, and the ability of the power system to supply electricity to meet this demand would be severely constrained. The low rates called for under real-time, streamflow-based rates would signal BPA customers to increase power consumption at a time when conditions would warrant discouraging consumption.

Another concern with streamflow rates is revenue stability. BPA's cost structure is about 85 percent fixed, and does not change with the amount of electricity sold. Streamflow-based electricity rates which change monthly would add to BPA's financial risk because of the increased variability of BPA's revenues.

BPA would lose load among the non-generating publics, who would be unable to predict BPA rates. They would seek the stability of long-term contracts with IOUs or possibly self-generation. Generating publics and DSIs would most likely purchase from BPA during wet years and other times when BPA streamflow rates are low, and purchase on the open market when power is available at rates below BPA's rates. Load loss could range from 800 to 1,200 aMW in 2002. Most of this firm power surplus would be sold to the nonfirm market. The difference between the average PF and the nonfirm market price would be about 17 mills/kWh. This could lead to a revenue loss of about $120 to $180 million annually. However, BPA could deliver up to 900 aMW of this power to IOUs under the in-lieu provisions in the residential exchange contracts. Because in-lieu power would be delivered to the IOUs at the PF rate, most of the lost revenues would be replaced by the in-lieu power sales. In addition, BPA's Residential Exchange costs would decrease by up to $70 million annually. Depending on the amount of load loss and the quantity of in-lieu power delivered, the net effect of this module could range from a $20 to $70 million reduction in BPA's costs, to a $180 million reduction in BPA's revenues. The rate effects range from a slight decrease to a 1.75 mill increase in BPA rates.

If BPA PF customers pass through this rate increase to their customers, extensive price-induced conservation could result, as customers reduce usage to avoid paying the higher rates.

This module is a variant to all alternatives except Status Quo. It would have similar effects in all alternatives; that is, both generating and non-generating customers would turn to sources of power other than BPA (IPPs, other utilities, and self-generation, probably supported by CT generation), and BPA would have substantial surplus power, which could be used to serve in-lieu loads of IOUs or would be sold at low nonfirm prices. The amount of revenue loss or cost reduction to BPA would depend on the amount of surplus in each alternative, the degree to which in-lieu loads could be served, and the amount of power that would have to be sold at nonfirm rates.

Environmental Impacts

The environmental impacts of this module would be similar to those of module RD-1 (Seasonal Rates-Three Periods); however, the rates uncertainties associated with this module may lead more utilities to shift load away from BPA and turn to other power sources throughout the year, not just during winter months. The result could be additional regional development of new generating resources, particularly CTs (with their air quality, water use, and land use impacts), and increased BPA surpluses. To the extent that BPA could use surplus load to serve in-lieu loads of IOUs, the BPA surplus could offset some portion of those utilities' new resource requirements.

4.5.2.3 Streamflow Seasonal Rates - Historical (RD-3)

Module Description

In this module, BPA's firm power rates would be seasonally differentiated, and would be higher in months with higher streamflows (spring and summer) and lower in months with lower streamflows (fall and winter). In contrast to the previous module (Streamflow Seasonal Rates—Real Time), rates would not be set on a month-by-month rate to reflect actual streamflows; rather, they would be based on historical average flows in each month. This would allow rates to reflect normal year streamflows, but with more predictability than if rates were adjusted monthly to reflect actual streamflows.

Effects of Module on Alternatives

The effects of this module would be comparable to those of the Seasonal Rates - Three Periods module described above. This module is a variant under all alternatives except BPA Influence. In all cases, impacts would be similar: generating publics would be likely to place more of their load on BPA in spring and summer months, when rates are lower, and less during fall and winter months, when rates are higher. During periods when they do not place load on BPA, these utilities are likely to rely on power purchases, probably supported by existing thermal generation or CTs. The extent to which utilities place more load onto BPA in low-rate months and take it off BPA in high-rate months would depend on the extent to which rates vary by month compared to the rates for alternative power supplies during those same months.

Environmental Impacts

The impacts would be largely comparable to the three-period historical rate described above—that is, increased seasonal reliance on power purchases supported by the development and operation of combustion turbines, with consequent impacts on air quality and land and water use.

4.5.2.4 Eliminate Irrigation Discount (RD-4)

Module Description

BPA received comments during review of the DEIS suggesting that it eliminate the irrigation discount in the current rate structure, in order not to encourage the diversion of water from the Columbia and Snake River systems for irrigation. BPA currently provides a rate discount of approximately 5 mills/kWh to preference customer utilities to serve loads used to irrigate or drain fields for agricultural purposes.

Effects of Module on Alternatives

The market and environmental impacts of the irrigation discount were addressed in BPA's 1993 Wholesale Power and Transmission Rate Environmental Assessment (DOE/EA-0838, or BPA publication DOE/BP-2204, July 1993). According to that document, eliminating the irrigation discount could lead to a total regional irrigation load decline ranging from 5 to 10 percent, or up to approximately 30 aMW (total irrigation loads on BPA vary considerably, but are estimated to be approximately 300 to 350 aMW in 1995). Effects on BPA's total firm loads would be considerably smaller, because irrigation loads are only a small proportion of BPA total loads. The elimination of the irrigation discount would have a very small positive impact on BPA's revenues and rates to other BPA customers; however, the rate increase to irrigating utilities would be offset somewhat by a loss in irrigation loads. The overall impact on BPA's revenues and rates probably would be less than 0.1 mill/kWh.

This module would have essentially the same effect if implemented in any of the alternatives. In all cases, impacts on BPA's revenues and rates would be very minor.

Environmental Impacts

Implementation of this module (that is, elimination of the irrigation discount) would have several environmental impacts—it could motivate some irrigators to increase the efficiency of irrigation, thereby reducing water use for farming; it could lead to some changes in crops (to crops that require less water); and it could increase farming costs, potentially to the point that some farms could no longer operate economically and would go out of business. To the extent that irrigators are able to obtain replacement power from other suppliers at prices comparable to BPA's rates with the irrigation discount, the effects described below will not occur.

The 1993 Rates EA predicted that for each 10 aMW of irrigation load reduction, up to 3,000 hectares (ha) (7,500 acres) of land might be removed from production and up to 0.2 km3 (0.15 MAF) less irrigation water might be used. If, in extreme cases, elimination of the irrigation discount reduced loads as much as 30 aMW as a result of curtailments, irrigation water use might be reduced by up to 0.6 km3 (0.5 MAF), and up to 8,000 ha (20,000 acres) of land might be removed from production. In the unlikely event that all of the irrigation water came from surface water or from groundwater hydrologically connected to surface water sources (which is not the case), up to a half-million acre feet of water might be returned to surface water, including the Columbia and Snake River systems. Some of this water could be available for flow augmentation to enhance downstream passage of anadromous fish, even though the quantity is not substantial.

Farmers faced with increased costs of pumping would shift to less energy-intensive methods of farming. Generally, such a shift also reduces water consumption, as farmers use more water-conserving irrigation methods (such as higher-efficiency sprinkler systems) and grow less water-intensive crops. Farms where irrigation involves high-head pumping operations could become uneconomical, and farmers in such situations could go out of business. Most of these operations are located in arid parts of the region in areas of sandy soils. Without irrigation, grazing would be the likely alternative agricultural use of these lands.

4.5.2.5 Variable Industrial Rate (RD-5)

Module Description

BPA currently serves the DSI aluminum smelters under the Variable Industrial (VI) Rate, through which the price of electricity varies (with a lower and an upper limit) with the price of aluminum. Aluminum ingots are a commodity that is traded on international exchanges. The aluminum price is subject to considerable volatility, and ranged from $.45/lb. to $1.20/lb. between 1986 and 1994. Aluminum production is very sensitive to electricity costs because they account for about one-third of the cost of production, and electricity is the only component of the cost of producing aluminum that varies significantly throughout the world. Because the aluminum DSI loads account for about 30 percent of BPA's revenues, the swings in the smelter load caused severe financial problems for BPA due to uncertainty in revenues before it implemented the VI rate in 1986.

The current VI rate ranges from about 20 mills/kWh during periods of low aluminum prices, to about 33 mills/kWh when aluminum prices are high, with a plateau set at the base or 7(c)(2) DSI rate. Implementation of the VI rate in 1986 led to the reopening of three closed smelters under new ownership, and the restart of another that had been closed for over a year. The VI rate stabilized BPA's smelter load and provided significantly more revenue in the first 5 years of the rate than BPA would have received without it, although BPA's aluminum DSI revenues have been lower recently due to over-supply in the international market.

The VI rate stabilized the loads of aluminum DSIs and reduced the uncertainty of BPA's revenues due to unpredictable changes in the price of aluminum. This revenue uncertainty caused concern among BPA's utility customers because of the effect on BPA's firm power rates when additional revenues were required during periods of low aluminum prices. Although there is some variability in DSI revenues under the variable rate, the revenue reduction is less than if they curtailed production or shut down permanently when aluminum prices dropped, as they did under the IP rate. In addition, under the variable rate, BPA has the opportunity to recoup revenue losses when aluminum prices are high. Under the IP rate, the revenue variation is always down.

This module assumes that the VI rate would continue in its current form. Assuming a base (plateau) DSI rate in 2002 of about 29 mills/kWh, the VI rate would range from 19 mills/kWh during periods of low aluminum prices to 39 mills/kWh during periods of high aluminum prices.

Effect of Module on Alternatives

Estimating the effect of the VI rate depends on a large number of factors that are difficult to predict. The effectiveness of the VI rate depends on the profitability of the PNW smelters at the basic DSI rate, the long-term price of aluminum, BPA's load/resource balance, the price of power in the nonfirm and surplus firm market, and BPA's financial condition.

Scenarios for a VI rate that would have any effect on the level of BPA's DSI loads would require that the smelters could operate profitably at the base DSI rate, that BPA be in load/resource balance or surplus, and that rates in the nonfirm market be at or below the lower limit of the VI rate. If gas prices remained low and BPA continued to lose PF load to other utilities and self-generation, the VI rate could be a way of preventing a similar defection of DSI load and lead to greater revenue stability for BPA.

However, if (1) BPA were not able to set the base DSI (or plateau) rate at a level that would allow profitable operation for the smelters with BPA power instead of other power sources, (2) nonfirm prices were above 20 mills/kWh, and (3) BPA were successful in maintaining PF load, a VI rate might not offer benefits to BPA and its other non-DSI customers.

Because of the great number of uncertainties associated with this module, specific impacts for each alternative cannot be estimated. The types of impacts associated with this module would be similar among all alternatives to which it applies as a variant (all alternatives except Status Quo, for which the VI rate is intrinsic).

Environmental Impacts

DSI operations likely would remain unchanged, because the current predictions of aluminum prices and DSI products and the costs of alternative power suggest that DSIs will continue to operate whether or not they are served by BPA. Only if major unpredicted changes occurred in aluminum prices or alternative power costs would this module affect the level of DSI operations.

The primary effect of this module would be on the amount of DSI load served by BPA or by other power sources such as power purchases, self-generation, IPPs, or other utilities (most likely supported by the development and operation of CTs). Implementing this module might, under the right market conditions, lead to higher DSI loads on BPA and therefore less development of alternative supplies.

4.5.2.6 Load-Based Tier 1 (RD-6)

Module Description

BPA would develop the size of Tier 1 based on a percentage (for example, 90 percent) of historical loads for each customer. In a month when Federal system resources were not sufficient to meet Tier 1 loads, BPA would purchase power on the open market to equalize the FBS resources and the Tier 1 load. The balance of the load (for example, 10 percent) would be served at Tier 2.

Effects of Module on Alternatives

Effects of this module would be similar among all the alternatives to which it applies—BPA Influence, Maximize Financial Returns, and Short-Term Marketing (it is intrinsic in Market-Driven BPA and would be incompatible with the objectives of Status Quo and Minimal BPA alternatives).

In any tiered rate structure, utilities with rapidly growing loads would purchase increasing amounts of more expensive Tier 2 power. As a consequence, they would have greater incentives to implement their own conservation programs or to turn to sources of power other than BPA (to the extent that other sources would be less costly than BPA’s Tier 2 rate). Utilities with slow or no load growth would have fewer incentives to implement their own conservation programs or to turn to other sources of power.

In a load-based tiered rate structure, conservation incentives and incentives to turn to other power sources would be more evenly spread across winter-peaking utilities and customers with flatter load shapes than under a resource-based structure.

Environmental Impacts

The primary environmental impacts of this module stem from the differing environmental impacts of different conservation and generating resource types (which are described generically in section 4.3 of this chapter). To the extent that a load-based Tier 1 rate led utilities experiencing load growth to continue to put loads on BPA, regional load growth would be served by the mix of resources BPA selects in its resource programs, which emphasizes conservation, renewables, and CTs. It is likely that if growing utilities put less load on BPA, they might rely more on meeting load growth with CTs or power purchases, which are predicted to be the lowest-cost resources available to serve load.

4.5.2.7 Resource-Based Tier 1 (RD-7)

Module Description

BPA would base the size of Tier 1 on a fixed percentage of FBS capability. The size of the resource-based Tier 1 would vary from month to month based on streamflows and the availability of other FBS resources. All additional power would be purchased at Tier 2. The allocation of this power would be based on the customers' historical loads. Purchased power would not be allocated to Tier 1. Under this proposal, BPA would assign a fixed set of resources to serve a portion of the customers' loads at the cost of those resources, and assign other firm resources to serve Tier 2 loads.

Effects of Module on Alternatives

The effects of this module would be similar among all the alternatives to which it applies—the Market-Driven BPA, Maximize Financial Returns, and Short-Term Marketing alternatives (This module would be intrinsic to BPA Influence, and is incompatible with the objectives of the Status Quo and Minimal BPA alternatives). Like load-based tiered rates, the effects of this module would be more pronounced for faster-growing utilities that would purchase greater amounts of BPA power at Tier 2 prices.

A resource-based Tier 1 would provide relatively greater price incentives to utilities with winter-peaking loads to implement their own conservation programs or find sources of power other than BPA, and smaller such price incentives to utilities with summer-peaking or flat loads. All BPA customer utilities would experience higher costs of increased Tier 2 purchases during winter low-flow months. Therefore, this module could affect the regional distribution of conservation development and the degree to which utilities place load on BPA.

Environmental Impacts

The environmental impacts of this module would depend on the degree to which the resource acquisitions of utilities shifting load away from BPA would differ significantly from BPA's resource acquisitions. In this module, utilities would face higher BPA rates in winter, and in response, might look to other power sources (such as CTs) or implement their own conservation programs.

4.5.2.8 Market-Based Tier 2 (RD-8)

Module Description

BPA would price power from Tier 2 based largely on the price of power on the wholesale market. BPA would hope to avoid defection of load to other suppliers and self-generation by pricing power slightly below the prevailing rate. If necessary, the price of Tier 1 would be increased to accomplish this pricing goal.

Effects of Module on Alternatives

BPA would set the Tier 2 rate slightly below the price of long-term power or the cost of alternative resources that existing customers could purchase for use as an alternative to BPA power; Tier 1 might absorb Tier 2 costs. This module would help BPA to maintain competitive prices for Tier 2 sales even when Tier 2 costs are above the market price, by supporting Tier 2 sales with Tier 1 revenues. Conversely, Tier 2 sales at the market price could reduce Tier 1 rates if Tier 2 costs were below the market price. When the market price is falling, this module would add to the uncertainty of Tier 1 prices and increase the loss of BPA utility firm loads.

Effects of this module would be similar among all the alternatives to which it applies—the BPA Influence and the Market-Driven alternatives. (This module would be intrinsic to Short Term Marketing and is incompatible with the objectives of the Status Quo, Maximize Financial Returns, and Minimal BPA alternatives.)

Environmental Impacts

The effect of this module on customers' decisions about placing growing loads on BPA probably would be mid-way between the Load-Based Tier 1 and the Resource-Based Tier 1 modules. As in those modules, the primary environmental impacts of this module would stem from the differing environmental impacts of different conservation and generating resource types (see section 4.3). To the extent that a market-based Tier 2 rate would lead utilities with growing loads to continue to place them on BPA, regional load growth would be served by the mix of resources BPA selects in its resource programs, which emphasize conservation, renewables, and CTs. If utilities put less load on BPA, they might tend to rely more on CTs to serve load growth.

4.5.3 Direct Service Industries Service

Under current market conditions, 2,700 aMW of DSI load is assumed to operate across all modules. The major question is whether BPA serves the DSI load, or whether it is served by other suppliers or self-generation. Increased competition in the generation market, increased access to BPA's transmission system, low natural gas prices and improved efficiency of CTs has made purchasing power from other suppliers or self-generation an increasingly attractive option for the DSIs. Prices for short-term power were in the 10 to 20 mill range during the winter of 1994-95, and the first-year cost for new CTs currently is at or below BPA's PF rate.

Therefore, the analysis of impacts of DSI rate and contract alternatives focuses on effects on BPA loads (and resulting impacts on generation and conservation development and operations). However, if market conditions changed substantially, DSI operations (which are expected to be the same across all Business Plan alternatives) could change. In that case, there could be increases or decreases in the environmental impacts of DSIs, shown on a per-megawatt basis on table 4.3-1. Table 4.5-2 shows DSI loads and rates for the six EIS alternatives which provide the "base case" for evaluating the DSI modules discussed below.

Table 4.5-2: Direct Service Industries Operations, Loads, Resources, and Rates Base Case for Evaluating Effects of DSI Modules (Nominal $ in 2002)

	Status Quo	BPA Influence	Market-Driven	Maximize Financial Returns	Minimal BPA	Short-Term Marketing
Total PNW DSI load (aMW)	2,700	2,700	2,700	2,700	2,700	2,700
BPA DSI load - firm (aMW)	1,600	400	2,500	2,500	1,900	1,900
BPA DSI load - nonfirm (aMW)	300	800	0	0	0	0
BPA DSI load - total (aMW)	1,900	1,200	2,500	2,500	1,900	1,900
DSI rate (mills/kWh)	30-34	28-32	27-31	27-31	26-30	27-31
Average nonfirm rate (mills/kWh)	15	15	15	15	15	15
PF rate for "in-lieu" sales	32-36	30-34	29-33	29-33	28-32	29-33
BPA "in-lieu" sales to IOUs (aMW)	900	900	0	0	0	300
BPA firm surplus (aMW)	1,600	1,900	0	0	0	0

The discussion of DSI policy modules below includes references to some special features of DSI service that affect BPA's sales and revenues. The following is a brief explanation of these features.

The DSI load, most of which is comprised of aluminum smelters which operate at almost 100-percent load factor, provides some important benefits to the Federal hydroelectric system. (Load factor is the ratio of the average usage to maximum (or peak) usage for a particular customer or customer class.)

One of these benefits arises from the interruptibility provisions in the current DSI power sales contracts. These contracts permit BPA to interrupt the DSI load for energy shortages (such as those resulting from low river flows during dry years), system emergencies, and loss of major generating plants or the interties. Without these interruption provisions, BPA would have to arrange for equivalent amounts of reserves from generation, such as gas- or oil-fired combustion turbines, which other utilities use to provide reserve power. The rate BPA charges DSIs (as required by the Northwest Power Act) reflects the value to BPA of the reserves provided by the DSIs.

Aluminum smelters and some of the other DSIs operate continuously, 7 days a week, 365 days a year. This constant load can be served at lower cost than the more variable loads of commercial or residential consumers, which require enough generation to meet total loads during peak hours of the day, but leave much of the same generation idle during the hours of lowest consumption in the middle of the night and on weekends.

The constant DSI load also allows BPA to make full use of hydro generation from the required minimum nighttime flows on the Columbia River. Without the large block of DSI nighttime loads, it might be necessary to spill water to maintain required flows, and lose the potential to generate power. The large nighttime loads also allow BPA to increase its revenues through power sales or exchanges with other utilities, both within the Northwest and in other regions, by allowing BPA to deliver power during the day when it has higher value, and to accept returns during the night. These transactions include capacity sales, capacity for energy exchanges, and seasonal exchanges (which help BPA to adapt to higher springtime flow requirements by exchanging springtime generation from the Columbia River system for wintertime generation from other resources).

4.5.3.1 Renew Existing DSI Power Sales Contracts (DSI-1)

Module Description

This module assumes that when the current DSI power sales contracts (PSCs) expire in 2001, the PSCs would be renewed in the same basic form as the existing contracts. The new contracts would serve three quartiles of the DSI load as firm for operations and planning purposes, and the fourth quartile subject to the interruption rights and provisions of the current DSI contracts. The rate provisions of section 7(c) of the Regional Act would continue to be the basis for setting the DSI rate.

Occasionally the DSIs have disagreed with BPA over the exact meaning of the top quartile restriction rights contained in the existing PSCs. The DSIs have wanted a more precise description of when and under what conditions the top quartile would be curtailed. Also, the DSIs have wanted a better description of their rights to and pricing of purchased power when the top quartile service is restricted, and have been concerned with limitations on power purchases from other suppliers. The DSIs, like large industrial customers elsewhere, would like to be able to purchase some portion of their load on the open market, and not be tied exclusively to BPA. These disputes over PSC interpretations suggest that renewing existing contract terms would meet with some objections from the DSIs.

Section 7(c)(2) of the Regional Act states that the DSI rate is to be based on the PF rate and the typical margins included by preference customers in their retail industrial rates, taking into account the size, character and other items including retail industrial rates. The DSI rate under Section 7(c)(2) is set by calculating the 7(b) or preference rate at the DSI load factor, adding the “typical margin” paid by retail industrial customers of preference customers, and subtracting the credit for value of reserves. This module assumes that the typical DSI margin calculation also remains unchanged from the current formula.

The DSI rate has averaged about 2 mills/kWh less than the average PF rate since the 1985 rate case. Although this differential may change over time, the 2-mill differential is assumed to continue in this module.

Effects of Module on Alternatives

This module is evaluated under the BPA Influence, Market-Driven BPA and Maximize Financial Returns alternatives. It would be intrinsic in the Status Quo alternative and would not be considered in either the Minimal BPA or Short-Term Marketing alternatives because renewing existing DSI power sales contracts would be inconsistent with the basic assumptions of those two alternatives.

Status Quo

This module is intrinsic to the Status Quo, and its implementation is likely to lead to a significant drop in the amount of DSI load served by BPA because of the unresolved issues between BPA and the DSIs over contract interpretation, the high cost of power to replace interrupted top quartile deliveries, and uncertainty of power supply. The amount of DSI load served by BPA would decline by about 600 aMW from current forecasted levels, to 1,900 aMW, due to DSI use of other sources of power (self-generation and purchases from other suppliers).

BPA Influence

The module that is intrinsic to this alternative is DSI firm service in the spring only, with interruptible service for the rest of the year. If BPA instead offered to renew the DSIs' existing power sales contracts in 2001, the portion of DSI load served by BPA would increase because the certainty of power supply would be more acceptable to DSIs than spring-only firm service.

If this module were implemented—that is, if tiered rates were not implemented, the existing DSI rate structure and contractual terms remained in place, and the limitation of firm service in the spring only removed—the DSI load served by BPA could increase to about 1,200 aMW of firm load and 700 aMW of nonfirm load. At this operating level, BPA's firm surplus would decrease to about 1,200 aMW. The increase in BPA's DSI load of about 700 aMW in this module would generate additional revenues for BPA because the DSI rate would be about 15 mills/kWh higher than the nonfirm rates for which the surplus would most likely be sold. This would generate about $90 million in additional revenues to BPA, reducing the rate increase otherwise predicted for this module by about 1 mill/kWh.

Market-Driven

In the Market Driven alternative, the percentage of DSI load served as firm declines over time. By substituting renewal of the existing DSI PSCs in 2001 for the tiered rates and declining firm service, BPA would see a drop in the amount of DSI load it served because of the interruptibility provisions of the existing PSCs, which (as noted above) are not favored by the DSIs because of the supply uncertainty they cause.

Implementing this module instead—that is, replacing the tiered rate structure planned for the long term with the existing DSI contracts—would result in a BPA DSI load loss under this alternative of about 600 aMW. The reason for this DSI load loss is that under current and forecasted market conditions, the DSIs increasingly find that the interruptibility conditions of the current DSI contract make it difficult to plan and operate. With the price of alternative power sources dropping, DSIs would find it easier to contract with other sources than to be subject to the uncertainties of BPA's interruptible top quartile service. BPA would probably deliver this power at the PF rate to utilities under the in-lieu provision of the residential exchange contracts. Doing so would increase BPA revenues by about $10 million annually because the average PF rate is estimated to be about 2 mills/kWh above the DSI rate. In addition, BPA would save about $40 million in Residential Exchange payments. There would be some additional costs because of the need to replace the reserves that had been provided by the DSIs, and also the potential for some operating difficulties because of the difference in the load shape of the residential exchange and DSI loads. However, the overall benefit to BPA of implementing this module would be about $50 million annually, potentially leading to approximately a 0.25 to 0.50 mill reduction in the PF rate.

Maximize Financial Returns

Impacts in this alternative would be similar in kind and magnitude to those described for the Market-Driven alternative.

Environmental Impacts

As described in section 4.4.3.7, under DSI Load Effects, current projections of aluminum prices and the costs of alternative energy sources suggest that approximately 2,700 aMW of DSI loads will operate in all alternatives, whether or not this load is served by BPA. Therefore, implementation of this module would not affect levels of DSI operations (and associated air quality impacts); it would affect only whether the DSIs were served by BPA or other sources.

Moving DSI load from BPA to other power sources (such as power purchases, IPPs, or other utilities) probably would increase the development and operation of CTs, leading to predictable increases in NOx, CO, and CO2 emissions from these new thermal generating resources. However, BPA would also be left with surplus firm and nonfirm power, at least at certain times of the year. This surplus could be used by BPA to serve in-lieu loads of IOUs that participate in the residential exchange program, thereby reducing their need to develop new resources to serve load growth. The surplus might also be available regionally to displace higher-cost thermal resources (e.g., coal). The net impact of increased development and operation of inexpensive and relatively clean gas-fired CTs and the displacement of existing older thermal resources and coal might be a positive impact on air quality.

The effect of moving DSI load from other sources back on to BPA would be the opposite of the effects just described (e.g., less CT development and operation, and potentially, more operation of existing higher cost thermal resources).

4.5.3.2 Firm DSI Power in Spring Only (DSI-2)

Module Description

BPA would offer firm service to the DSIs during the 4-month flow augmentation period each spring. For the rest of the year, BPA would serve the smelters on an interruptible basis. To the extent that BPA could not supply the DSIs' power needs, they would purchase power on the open market. The DSI load served by BPA under this module is estimated to be about 400 aMW of firm power and 800 aMW of interruptible power. The balance of DSI load probably would be served from other sources or through self-generation. The DSI companies could decide to abandon BPA altogether if firm service were offered only in the spring. Aluminum smelters in particular require a stable and certain power supply for producing primary aluminum, and are very sensitive to changes in electricity price. The uncertainty of having half their load interruptible, forcing them into the open market, could prove to be too risky for the companies, which could instead decide to place all their load on other, more predictable sources.

Effects of Module on Alternatives

This module is considered intrinsic to the BPA Influence alternative, and a variant that could be applied to all other alternatives (except Status Quo, which assumes current DSI contract provisions).

BPA Influence

This module is intrinsic to the BPA Influence alternative. The aforementioned concerns over certainty of power supply would lead to a loss of about 1,300 aMW of BPA DSI load. BPA would serve about 400 aMW of firm DSI load and 800 aMW of nonfirm DSI load in this alternative. The DSIs' production processes, particularly aluminum smelting, require large amounts of electricity with a high degree of certainty of delivery. Offering firm service in the spring only would result in a large loss of load to other suppliers and self-generation, primarily because of DSI concerns over certainty of supply.

Market-Driven

DSI service under the Market-Driven alternative uses tiered rates with the percentage of DSI service declining over time. Substituting the firm DSI power in spring only module in this alternative would result in a significant drop in the amount of DSI load served by BPA because of DSI concerns over interruptions in power supply. Under DSI service conditions intrinsic to this alternative, the DSI load in 2002 served by BPA is estimated to be about 2,500 aMW. Implementing this module instead would reduce BPA loads by about 1,300 aMW. BPA probably would deliver 900 aMW of this power at the PF rate to utilities under the in-lieu provision of the residential exchange contracts. Doing so would increase BPA revenues by about $15 million annually because the average PF rate is estimated to be about 2 mills/kWh above the DSI rate. In addition, BPA would save about $65 million annually because of reduced Residential Exchange payments to utilities. BPA would incur some additional costs to replace the reserves provided by the DSIs. There would also be some potential to lose capacity sales and seasonal exchanges due to the reduction in BPA's DSI nighttime loads, which allow the Northwest power system to accept nighttime energy returns. There could also be operating problems because of the difference in the load shape of the residential exchange and DSI loads, which would increase daily peaking demands on BPA. The costs of replacing reserves, losing some capacity sales and exchanges, and addressing operating problems might total about $125 to $150 million annually.

BPA would have a surplus of about 400 aMW if this module were implemented in this alternative. Most of this surplus would probably be sold as nonfirm power on the open market. The difference between the DSI rate and the nonfirm rate would be about 15 mills/kWh in 2002. This would result in a revenue loss to BPA of about $50 million annually.

The total effect would be to increase BPA's revenue requirement about $100 to $125 million annually, leading to a rate increase of about 1 mill/kWh if rates could be increased without exceeding the maximum sustainable revenue level. If not, BPA would need to adopt response strategies to balance costs with revenues.

Maximize Financial Returns

The effects on BPA of implementing this module in this alternative would be almost the same under this alternative as under Market-Driven. The effect could be about a $100- to $125-million loss in BPA revenues annually, leading to a rate increase or revenue shortfall.

Minimal BPA

DSI service conditions intrinsic to the Minimal BPA alternative would use rates slightly below those in the Status Quo with the amount of power sold as firm declining over time to about 1,400 a MW in 2002, because BPA would not be acquiring new resources to meet preference customer load growth.

If this module were implemented instead—adding a restriction of firm service in the spring only—BPA would probably lose an additional 700 aMW of DSI load to other suppliers or to self-generation because of DSI concerns over interruptions in power supply. The power not sold to the DSIs would be delivered to the IOUs at the PF rate under the in-lieu provisions of the residential exchange contract, resulting in an increase in BPA revenues of about $12 million annually because the average PF rate is about 2 mills/kWh above the DSI rate. In addition, BPA would save about $50 million annually because of reduced Residential Exchange payments to utilities. There would be additional costs of replacing reserves and problems associated with load shapes and nighttime returns (mentioned above under Market-Driven BPA), resulting in cost increases totaling about $125 to $150 million annually. The total effect would be to increase BPA's revenue requirement about $65 to $90 million annually. This would result in a net increase of BPA rates of about 0.75 mills/kWh, or a revenue shortfall if increased rates were to exceed the maximum sustainable revenue level.

Short-Term Marketing

The Short-Term Marketing alternative assumes that the amount of DSI firm load served by BPA would decline over time to about 1,900 aMW in 2002. If, in addition, firm service were restricted to the spring, BPA would probably lose another 700 aMW of DSI load to other suppliers or to self-generation. Because BPA would already serve 300 aMW of in-lieu load in this alternative, 600 additional aMW of the DSI load would be sold to utilities under the in-lieu provision of the residential exchange contracts at the PF rate and 100 aMW would be sold on the open market, probably at nonfirm rates. The increase in revenues from sale of power at the PF rate, which is about 2 mills/kWh higher than the DSI rate, would offset the revenue loss of the 100 aMW of

DSI firm power sold at nonfirm rates. BPA would also save about $50 million annually from reduced Residential Exchange payment to participating utilities. Replacing reserves and problems associated with load shapes and nighttime returns (mentioned above under Market-Driven), would lead to additional costs of about $125 to $150 million annually, and a net rate increase of about 0.75 mills/kWh (if such an increase would not exceed maximum sustainable revenues).

Environmental Impacts

Current projections of aluminum prices and the costs of alternative energy sources suggest that approximately 2,700 aMW of DSI loads will operate in all alternatives, whether or not this load is served by BPA. Therefore, implementation of this module would have no effect on levels of DSI operations (and associated air quality impacts), but would only affect whether the DSIs are served by BPA or other sources. The types of environmental impacts that might result from DSI loads' moving from BPA to other sources are described above (4.5.3.1, Renew Existing DSI Power Sales Contracts): increased development of CTs, increased in-lieu energy deliveries to IOUs' residential exchange loads (reducing their need for new resources), and displacement of existing higher-cost thermal resources such as coal. This module would have no impact on the operation of the hydroelectric system, because the future hydroelectric operations are being decided through the System Operation Review process, which will set hydroelectric operations parameters within which all BPA operations will occur.

4.5.3.3 Declining Firm Service (DSI-3)

Module Description

In this module, the amount of DSI firm load served by Tier 1 power would decline over time, with the goal of keeping the percentage of DSI load served at the Tier 1 price comparable to the percentage of preference customers' loads served with Tier 1 power. Under tiered rates based on historical loads, as the preference customers' loads grow, a declining percentage of preference customer loads would be served by Tier 1 power. Because the DSI load is limited under the Northwest Power Act, it would not grow like the preference customer load. Without some mechanism to reduce the DSI Tier 1 allocation, DSIs could eventually receive a greater percentage of Tier 1 power than PF customers. Declining firm service is an attempt to address this issue.

At least three methods could be used to achieve a declining DSI Tier 1 allocation:

- The proportion of DSI load covered by the DSI Tier 1 allocation could decline at the same rate as the proportion of preference customer load covered by Tier 1 allocation.
- Portions of the DSI Tier 1 allocation could be subject to recall if needed to serve Tier 1 loads of preference customers.
- The DSI Tier 1 allocation could decline at a fixed percentage over time, e.g., the DSIs could start out with an initial Tier 1 allocation of 75 percent, and Tier 1 service would decline by 1 percent per year until it reaches 55 percent.

Effects of Module on Alternatives

This module is considered intrinsic to the Market-Driven BPA, Minimal BPA, and Short-Term Marketing alternatives, and could be applied as a variant to the BPA Influence and Maximize Financial Returns alternatives. It is incompatible with the assumptions of the Status Quo alternative, which reflects current DSI contract terms.

BPA Influence

Under DSI service conditions intrinsic to this alternative, the DSIs would be offered firm service in the spring only and would be served with interruptible power for the balance of the year. BPA's DSI load in 2002 would be about 400 aMW of firm load and 800 aMW of interruptible load.

If DSIs were instead offered a larger amount of power as firm (e.g., 75 to 90 percent), even if the amount declined over time, BPA's DSI loads would increase because of the DSIs' increased certainty of power supply. It is likely that DSI load level would therefore be more like that of the Status Quo alternative; that is, BPA would regain perhaps 700 aMW of loads that would otherwise be lost in this alternative. BPA's firm surplus would decline from approximately 1,800 aMW to 1,100 aMW. Since most of this surplus would probably be sold at nonfirm rates, if this module were implemented, BPA's revenues could increase approximately $100 million annually because the DSI rate is about 15 mills/kWh higher than the nonfirm rate. The effect could be to reduce BPA's rates by approximately 1 mill/kWh.

Market-Driven BPA

This module is intrinsic to the Market-Driven alternative. BPA's efforts toward controlling costs and offering competitive rates and improved contract conditions lead to about 2,500 aMW of DSI load served by BPA in the short term; over time, this amount of DSI firm load would decline with the declining firm service. This represents an increase in the amount of DSI load served by BPA of about 600 aMW compared to the Status Quo. By keeping rates to the DSIs at or below the cost of alternative suppliers, the DSIs would find leaving BPA a less attractive option, at least in the short term.

Maximize Financial Returns

Under assumptions intrinsic to this alternative, DSIs are offered 100-percent firm service, and BPA keeps rates low enough so that BPA serves about 2,500 aMW of DSI load in 2002. This amount is the same as in the Market-Driven alternative. Replacing the assumption that DSIs are offered 100-percent firm service with the assumption of this module, that DSIs are offered declining firm service, would probably result in little or no change in DSI load served by BPA in 2002 under this alternative, because the schedule for reductions in BPA firm power allocated to DSIs declines by only 1 percent per year and would not exceed DSI load already lost to BPA by 2002. Consequently, there should be very minor effects on BPA revenues and rates.

Minimal BPA and Short-Term Marketing

Declining Firm Service is assumed to be intrinsic to these two alternatives. Effects in these alternatives would be similar in kind and magnitude to those described in the Market-Driven alternative.

Environmental Impacts

This module is likely to affect only whether DSI loads are served by BPA or other energy suppliers, and not the level of operations of DSIs. In the short term, in most alternatives, this module would lead to increased DSI loads on BPA, and less load placement on other suppliers. This would probably mean less development of new generating resources (probably CTs) and more operation of existing thermal generation with somewhat greater air quality impacts. In the longer term, DSI loads would move off BPA to other suppliers—leading in the long term to increased development of generating resources by energy suppliers other than BPA and a long-term improvement in air quality.

4.5.3.4 No New Firm DSI Power Sales Contracts (DSI-4)

Module Description

Some commenters suggested that BPA should not offer long-term firm service to the DSIs when the existing power sales contracts expire in 2001. Under this module, BPA would not offer firm power contracts to DSIs, but they would be able to purchase nonfirm power when it is available. In 2002, the base DSI rate is estimated to be about 29 mills/kWh and the average price of nonfirm power about 14 mills/kWh. To the extent BPA could not supply the DSIs with nonfirm power, the DSIs would be expected to purchase power on the open market or install CTs for self-generation.

Effects of Module on Alternatives

This module could apply as a variant to all alternatives except Status Quo (which is limited to provisions of the current DSI contracts).

BPA Influence

Intrinsic to this alternative is that the DSIs would be offered firm service in the spring only and would be served with interruptible power for the balance of the year. If instead BPA were to decline to offer new PSCs to the DSIs and only allow them to purchase nonfirm power when available, it is likely that most if not all of the smelters would seek out alternative suppliers or install their own generation. Under the BPA Influence alternative, the amount of DSI load served by BPA in 2002 is estimated to be about 400 aMW of firm load and 800 aMW of interruptible load. Denying the DSIs access to firm power would cause a loss of an additional 400 aMW of firm power sales and most, if not all of the nonfirm load.

If BPA were to lose 400 aMW of firm DSI load, given the statutory restrictions on sales to non-preference and out-of-region customers, BPA would have difficulty finding alternative purchasers for this quantity of power at prices near the DSI rate. Assuming that the difference between the DSI rate and nonfirm power is 15 mills/kWh, the revenue loss to BPA would be about $50 million annually. The loss of 800 aMW of nonfirm power would probably be revenue-neutral because the price BPA charged the DSIs for nonfirm power would probably be close to the market price for nonfirm power. BPA would likely experience a 0.5 mill increase in rates to other customers.

Market-Driven BPA

DSI service intrinsic to the Market-Driven alternative uses tiered rates in the long term, with the DSI load served as firm declining over time to about 2,500 aMW in 2002. Denying the DSIs access to BPA firm power would cause a loss of 2,500 aMW of firm power sales and would probably result in most, if not all, of the DSIs shifting to alternative suppliers or self-generation.

The 2,500 aMW of power not sold to the DSIs would be difficult for BPA to sell at firm power prices because of the legal constraints on BPA’s long-term firm power sales. BPA would exercise the in-lieu provisions of the Residential Exchange contracts and deliver about 900 aMW of in-lieu power at the PF rate. Because the PF rate is about 2 mills/kWh higher than the DSI rate, in-lieu deliveries would result in a $15 million increase in BPA revenues. BPA also would save about $65 million annually because of reduced Residential Exchange payments to participating utilities. The rest of the power, or 1,600 aMW, probably would be sold as nonfirm. Assuming a 15-mill difference between the DSI rate and the average nonfirm rate, the revenue loss to BPA could be about $210 million annually. The combined effect of these in-lieu deliveries and nonfirm sales could be about a $125 million decline in BPA revenues. In addition, the costs of replacing reserves, losing some capacity sales and exchanges and addressing operating problems might be $125 to $150 million annually. The total reduction in BPA revenues might be about $250 to $275 million annually, leading to about a 2.5 mill/kWh increase in other BPA rates, limited by the maximum sustainable revenue rate level.

Maximize Financial Returns

Impacts in this alternative would be similar in kind and magnitude to those described for the Market-Driven BPA alternative.

Minimal BPA

DSI service conditions intrinsic to the Minimal BPA alternative would result in rates slightly below those in the Status Quo, with the amount of power sold as firm declining over time to about 1,900 aMW in 2002 (because BPA would not be acquiring new resources to meet preference customer load growth). If BPA instead were to implement this module and decline to offer new PSCs to the DSIs, allowing them to purchase nonfirm power only when available, it is likely that most if not all of the smelters would seek out alternative suppliers or install their own generation.

With loss of the DSIs' 1,900 aMW of firm load, BPA would deliver about 900 aMW of power to the participating utilities under the in-lieu provisions of the residential exchange contracts. Because the PF rate is about 2 mills/kWh higher than the DSI rate, in-lieu deliveries would result in about a $15 million increase in BPA revenues compared to DSI service intrinsic to this alternative. As in Market-Driven, BPA also would save about $65 million annually because of reduced Residential Exchange payments to participating utilities.

The balance of the former DSI load could be sold on the open market as nonfirm power. However, assuming a 15-mill difference between the DSI rate and the average nonfirm rate, BPA would lose about $130 million in annual revenues. The combined effect of in-lieu deliveries and nonfirm sales would be a $50 million decline in BPA revenues. The additional costs of replacing reserves, losing some capacity sales and exchanges and addressing operating problems might total about $125 to $150 million annually. Therefore, the total reduction in BPA revenues would be about $175 to $200 million annually, or about a 2 mill/kWh increase in other BPA rates.

Short-Term Marketing

The Short-Term Marketing alternative assumes that the DSIs would be served under a market-based tiered rate structure, with the amount of firm power declining over time to about 1,900 aMW in 2002. If BPA were to implement this module instead, as in other alternatives most if not all of the smelters probably would seek out alternative suppliers or install their own generation.

With loss of the DSIs' 1,900 aMW of firm load, BPA would deliver an additional 600 aMW of power to the IOUs under the in-lieu provisions of the residential exchange contracts. With the higher PF rate, in-lieu deliveries would result in about a $10 million increase in BPA revenues. In addition, BPA would save about $47 million annually because of reduced Residential Exchange payments to IOUs. The balance of the former DSI power (1,300 aMW), would be sold on the open market as nonfirm power, with the 15-mill rate difference leading to a BPA revenue loss of about $170 million annually. The combined effect of in-lieu deliveries and nonfirm sales means an overall $125 million decline in BPA revenues. However, the costs of replacing reserves, losing some capacity sales and exchanges and addressing operating problems might be about $125 to $150 million annually. As a result, the total reduction in BPA revenues would be about $250 to $275 million annually, leading to about a 2.5-mill/kWh increase in other BPA rates.

Environmental Impacts

The effect of this module would be to decrease DSI loads on BPA, but not the level of DSI operations. More DSI load would be served by energy suppliers other than BPA, and as a result, there might be more development of new generating resources (probably CTs). Environmental impacts would be similar to those described for DSI-1 but far greater, due to the larger firm load loss.

4.5.3.5 100-Percent Firm Service (DSI-5)

Module Description

This module examines offering the DSIs 100-percent firm service. Under the current DSI power sales contract, three quartiles of the DSIs' power is firm, and one quartile is interruptible at BPA's discretion. Under a 100-percent firm service option, the DSI rate would be increased by up to 2 mills/kWh because the top quartile would now be served with firm power, instead of by nonfirm power. BPA would have 2,500 aMW of DSI load in this module.

Effects of Module on Alternatives

This module is intrinsic to the Maximize Financial Returns alternative, and could be a variant applied to all others except Status Quo (which reflects the provisions of the current DSI contracts) and Minimal BPA (in which there would not be enough resources available to serve all DSI load).

BPA Influence

Intrinsic to this alternative is that the DSIs would be offered firm service in the spring only and would be served with interruptible power for the balance of the year. Under those conditions, the DSI load in 2002 served by BPA is estimated to be about 400 aMW of firm load and 800 aMW of interruptible load because of the uncertainty of supply related to firm service in the spring only.

If this module were implemented instead, it is likely that most of the DSI load lost by BPA to alternative suppliers and self generation would be avoided because of the DSIs' certainty of power supply. As a result, the increase in BPA's DSI loads would be about 1,300 aMW. BPA's firm surplus would decline from 1,800 to 500 aMW. The sale of BPA surplus to the DSIs would result in an increase in BPA revenues of about $150 million because the DSI rate is about 15 mills/kWh higher than nonfirm prices. In addition, BPA would gain about $125 to $150 million from increased firm capacity and seasonal sales and by not having to replace DSI reserves. The total increase in BPA revenues as a result of implementing this module in the BPA Influence alternative would be about $300 million annually and would reduce BPA rates by about 3 mills/kWh.

Market-Driven BPA

DSI service intrinsic to the Market Driven alternative uses tiered rates, with the percentage of DSI load served as firm declining over time. If, instead, BPA offered 100-percent firm service in this alternative, the DSI load would probably remain close to the level of the early years of DSI service in this alternative, and not decline over time.

Maximize Financial Returns

The 100-percent firm DSI service module is intrinsic to this alternative and is assumed to be in large part responsible for the high level of DSI load served by BPA, compared to the declining firm service which is intrinsic to this alternative, because of the higher quality and certainty of power supply. While the DSIs would lose the credit for nonfirm top quartile service currently contained in existing rates, BPA would still be able to offer the DSIs a rate that would be competitive with other suppliers. BPA would serve about 2,500 aMW of DSI load in this alternative.

Short-Term Marketing

The Short-Term Marketing alternative assumes that the DSIs would be served under a market-based tiered rate structure with the amount of firm power declining over time to about 1,900 aMW in 2002. If BPA were to implement this module instead and offer 100-percent firm service to the DSIs, the amount of DSI load served would likely increase to about 2,500 aMW, due to the increased certainty of power supply. BPA would meet its obligation to serve the increased DSI load primarily with short-term purchases, if power could be purchased at a cost below the rate the DSIs pay BPA for the power.

It is unlikely that BPA would experience any significant change in rates by implementing this module under this alternative, because the DSI rate would be about 2 mills/kWh higher with 100-percent firm service, increasing the likelihood that the additional power needed could be found on the short-term market. BPA would only serve additional DSI load if it could purchase power for it at or below the cost of service.

Environmental Impacts

The effect of this module would be to increase DSI loads on BPA, but not the level of DSI operations. Less DSI load would be served by energy suppliers other than BPA, and as a result, there might be less development of new generating resources (probably CTs), at least in the short term, and more operation of existing resources, including existing thermal generation, with their greater air quality impacts.

4.5.4 Conservation/Renewables

The policy modules discussed below lead to the development of different amounts of energy conservation and renewable resource generation. In general, the result of these developments is that these resources take the place of other types of generation that otherwise would be developed. Under current market conditions, most of the new generation planned is combustion turbines. The environmental effect of replacing new combustion turbines with conservation or renewable resources is to substitute the impacts of the conservation and renewables for the impacts of the combustion turbines. Figure 4.5-1 shows this effect in terms of the net impacts per average megawatt from replacing combustion turbines with energy conservation or wind or geothermal generation.

4.5.4.1 "Fully Funded" Conservation (CR-1)

Module Description

In this module, in addition to price-induced conservation resulting from BPA's tiered rates, BPA would continue to fund conservation at levels comparable to what it would fund under the Status Quo alternative without tiered rates. As shown in table 4.4-14 ("Additional BPA Efforts" category), BPA would acquire an additional 140 aMW of conservation by 2002 in the Market-Driven and Maximize Financial Returns alternatives, at a cost of about 41 mills/kWh. (The cost of conservation reflects the nominal 2002 cost of the resource, and should not be confused with the lower, real levelized values used in other BPA and Council planning documents.) In the Short-Term Marketing alternative, BPA would acquire an additional 250 aMW of conservation, at an annual cost of approximately $90 million.

Effect of Module on Alternatives

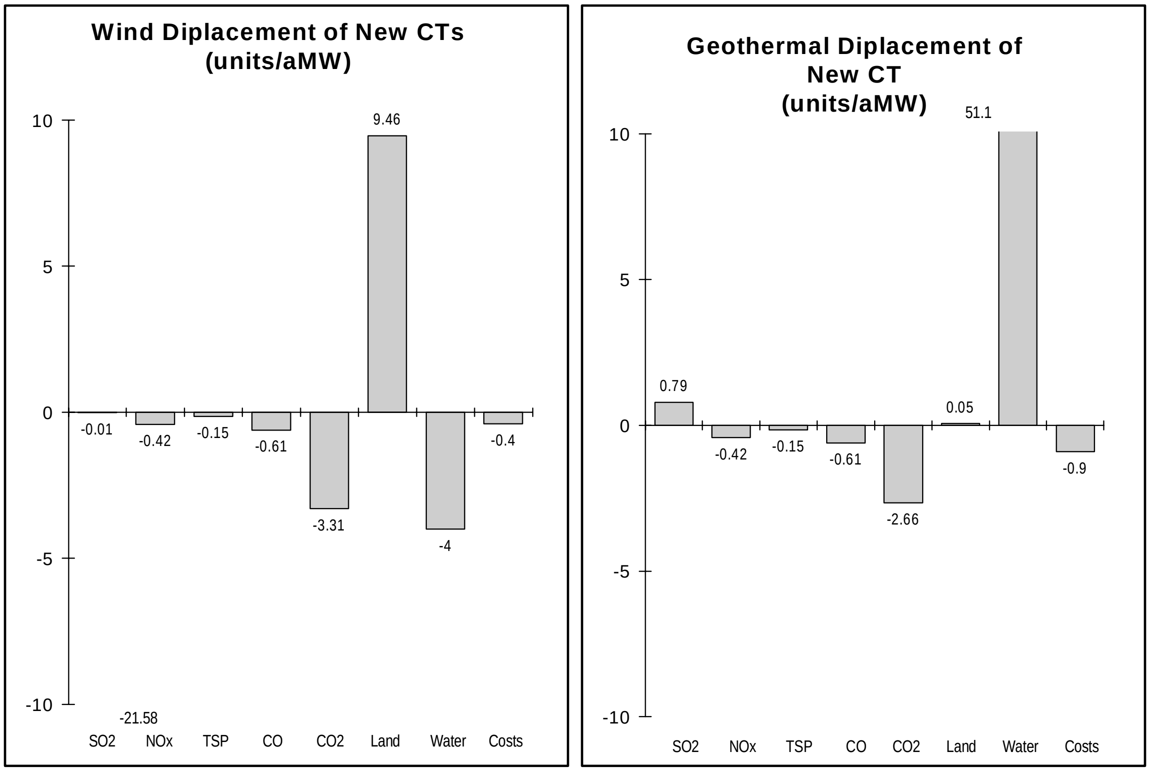
Implementing this module in the Market-Driven and Maximize Financial Returns alternatives by acquiring an additional 140 aMW of conservation would increase BPA's overall costs by approximately $50 million annually. This would result in approximately a half-mill/kWh increase in BPA's rates. In the Short-Term Marketing alternative, acquiring 250 aMW of additional conservation would cost approximately $90 million annually, increasing rates by almost one mill/kWh. Under the Market-Driven, Maximum Financial Returns, and Short-Term Marketing alternatives, the increased PF rate would lead to higher load loss among BPA's preference and DSI customers.

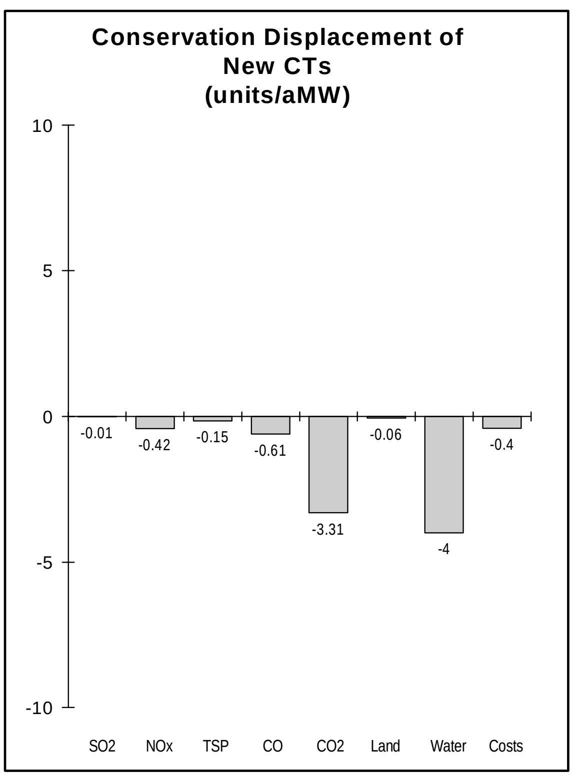
Environmental Impacts

It is likely that increased conservation acquisition would reduce regional acquisition of combustion turbines and/or cogeneration. Reductions in CT and cogeneration acquisition and operation would reduce air quality, water use, and land use impacts of these resource types (identified on a per-megawatt basis in table 4.3-1, Typical Environmental Impacts From Power Generation and Transmission). The amount of the reduction would depend on the amount of conservation acquired and the corresponding reduction in CT and cogeneration acquisition. For example, if the Fully Funded Conservation module were applied to the Market-Driven BPA alternative, BPA would acquire approximately 140 aMW additional conservation, but it is likely that with BPA fully funding conservation programs, other regional utilities would not implement as many conservation programs (that is, regional utilities would have targeted the same conservation savings that BPA

FIGURE 4.5-1

Net Air, Land, and Water Impacts From Conservation/Renewable Resources Replacing CTs





SO2 (sulfur dioxide) - Tons/aMW
NOx (nitrogen oxides) - Tons/aMW
TSP (total suspended particulates) - Tons/aMW
CO (carbon monoxide) - Tons/aMW
CO2 (carbon dioxide) - 1000 Tons/aMW
Land - Hectares/aMW
Water - 1000 Meters^3/aMW
Environmental Costs - $1000/aMW

As conservation or renewable resources are used to meet portions of regional firm loads rather than new CTs, not only is their energy output substituted for CT output, but the environmental impacts of their operation are also substituted. Figure 4.5-1 shows the environmental impacts per average megawatt of energy for replacing new CTs with conservation or renewable resources. Impacts of new CTs would not be offset if conservation and renewable resource development contributed to a surplus of BPA energy resources.

pursues), and the total regional increase in conservation would be only 30 aMW (see table 4.4-14, “Total Conservation for BPA Loads in 2003” category).

If the regional increase in conservation acquisition were 30 aMW, CT operations would probably be reduced by the same amount. NOx, SO2, CO, and CO2 emissions would be reduced somewhat, although overall, air quality impacts of existing and new thermal resource operations (expressed in dollar terms as environmental cost estimates, based on the environmental costs shown in table 4.4-20) would be reduced by only approximately one-third of one percent (a reduction from about $332 to $331 million).

If regional conservation acquisition were greater, the reduction in CT operations impacts would be correspondingly larger. For example, in the Maximize Financial Returns alternative, the region is predicted to acquire 140 aMW additional conservation with the implementation of the fully funded conservation module (table 4.4-14). In that case, air quality impacts of new and existing thermal generation (as measured in terms of environmental costs) would be reduced by approximately 1.5 percent (from approximately $344 to $339 million).

4.5.4.2 Renewable Resource Incentives (CR-2)

Module Description

BPA would develop an incentive proposal for renewable resources that would equal up to 10 percent of the cost of the qualifying resource. The incentive would take the form of a discount on BPA rates and the services used to get the renewable resource power to load. The discount would be incorporated into separate tariffs for utilities that develop or purchase renewable resources, for such power-related services as transmission, shaping, and reserves. The maximum discount available to any utility for any single resource would be 10 percent of the total cost of the renewable resource.

BPA would also incorporate provisions in its resource acquisition program that would require that the estimated incremental cost of a renewable resource would not be treated as greater than any non-renewable resource unless the cost of the renewable resource were greater than 110 percent of the cost of the non-renewable resource.

The market transformation potential for renewable resources in the Pacific Northwest is estimated at between 450 and 600 aMW. BPA currently is acquiring 80 aMW, and the rest of the region is acquiring 100 aMW. For purposes of this module, it is estimated that no additional renewable resources would be acquired by BPA and regional utilities because the 10 percent incentive is not enough to reduce the cost of renewables to a level that is competitive with the cost of CTs. The combination of low gas prices, low prices for power on the wholesale market, and improvements in CT technology have increased the cost differential between CTs and renewables. The 10 percent incentive would reduce the cost of a 75 mill/kWh renewable resource by about 7.5 mills/kWh. Comparable current CT costs are about 25 mills/kWh, significantly below the lower renewable resource cost. If completion of demonstration renewable resources results in greater economies for further development, the cost of renewable resources could drop, perhaps by 25 percent. Their cost would then be about 55 mills/kWh, and a 10-percent incentive would reduce the cost to about 50 mills/kWh, still roughly twice the cost of new CT generation.

Effect of Module on Alternatives

Because this module would not result in additional acquisition of renewable resources by regional utilities or BPA, this module would have little or no effect on the amounts of renewables acquired regionally in each alternative.

However, BPA incentives could reinforce existing commitments by other power suppliers to develop renewable resources, by lowering the costs of those committed renewable resource projects. Incentives could potentially affect resource decisions that were not driven solely by economic reasons, for example, where a developer or utility was willing to construct renewable resources to achieve environmental benefits, to diversify their resource portfolio, or to avoid fuel price risk that would affect CT generation.

Environmental Impacts

As noted above, this module is not predicted to have much effect on the amount of renewable resources acquired in the region, and therefore would have little or no environmental effect.

If incentives did result in incremental additions to regional renewable resources, it is likely that additional renewable resource acquisition would replace or reduce the acquisition of CTs or cogeneration. The resulting environmental impacts would be a reduction in the air quality, water use, and land use impacts of these resource types (identified on a per-megawatt basis in Table 4.3-1, Typical Environmental Impacts From Power Generation and Transmission). This overall positive environmental impact would be offset to a slight extent by the greater land use impacts of renewables. (As shown in table 4.3-1, renewable resources tend to be fairly land-intensive.)

4.5.4.3 - Maximize Renewable Resource Acquisitions (CR-3)

Module Description

With the goal of accelerating market transformation and the development of renewable resource technology, BPA would acquire a significant amount of all available commercial renewable resources developed in the Pacific Northwest, regardless of cost. The increment of renewable resources acquired by 2002 would be 300 aMW in the BPA Influence, Market-Driven, and Maximize Financial Returns alternatives, and 380 aMW in the Short-Term Marketing alternative (in addition to renewable resource projects already in progress). BPA acquisition of renewables would occur in increments of about 45 aMW per year through 2002.

Renewables are assumed to consist of 60 percent wind and 40 percent geothermal resources. The nominal cost in 2002 of wind resources is projected to be between 60 and 75 mills/kWh, and the cost of geothermal resources between 80 and 100 mills/kWh. The melded cost in 2002 of this pool is estimated to be about 75 mills/kWh.

Effects of Module on Alternatives

Renewable resources would most likely replace CTs or short-term power purchases in BPA's resource portfolio. Acquisition of 300 to 380 aMW of renewables by 2002 would place BPA in the position of delaying conservation programs, changing its resource acquisition program, and/or creating a surplus. The assumption in this module is that BPA would continue with its conservation acquisition program and that the renewables would replace the 230 aMW of CT/cogeneration resources BPA had intended to acquire; the additional amount of renewables (the 70 to 150 additional aMW above the amount that would replace CT/cogeneration resources) would add to BPA's surplus.

With the continued fall in the price of natural gas and the increased competition in the independent power industry, the levelized cost of CTs is currently about one-third to one-half of the cost of renewable resources. In 2002, the cost of a CT is estimated to be 35 mills/kWh, and the average cost of renewables acquired by BPA would be 75 mills/kWh. If renewable resource costs drop by 25 percent as they become more commercialized, the average cost of renewables would be about 55 mills/kWh.

The incremental cost to BPA for the renewables it acquires in place of the CT/cogeneration resources it would otherwise acquire would be about 40 mills/kWh (the difference in the cost per kWh of CTs and renewables). The net annual increase in BPA's costs resulting from the 230 aMW of higher-cost renewable resources in place of CT/cogeneration resources would be about $80 million. The increase in BPA's costs resulting from the additional 70 to 150 aMW renewable resources would be between $45 and $100 million annually. The effect on BPA's costs from this module would be between $125 and $200 million annually. In 2002, this would increase the average PF rate by up to 2 mills/kWh or about 6 percent.

It is possible that some of the 70 to 150 aMW of surplus power resulting from the acquisition of additional renewables could be delivered to residential exchange loads of participating utilities as in-lieu energy. If this surplus could be sold at the PF rate, it would bring between $20 and $40 million annually. In addition, BPA's residential exchange payments would decline by $5 to $10 million because BPA does not make Exchange payments to utilities served with in-lieu power. This could reduce the 2 mills/kWh rate increase identified above to closer to 1.5 mills/kWh.

The effect on bills of ultimate consumers is uncertain for a variety of reasons. Retail rate effects would depend on the ratio of BPA purchased power costs to total costs and the total kWh sales for the utility.

The following example shows the retail rate effect for ultimate consumers at a hypothetical utility that is a full requirements customer of BPA:

Utility X - before renewables purchase

BPA purchased power costs	$10 million
Other utility costs	$11 million
Total costs	$21 million
Annual kWh sales	375 million kWh
Average retail rate	56 mills/kWh

Assume that the cost of BPA power increased by 1.5 mills/kWh and BPA purchased power cost increased by about $600,000. The results would be as follows:

Utility X - after renewables purchase

BPA purchased power costs	$10,600,000
Other utility costs	$11 million
Total costs	$21,600,000
Annual kWh sales	375 million kWh
Average retail rate	57.6 mills/kWh

The increase in the average cost of power at Utility X would be 1.6 mills, or about 3 percent.

The second example shows the retail rate effect for ultimate consumers at a hypothetical utility that is a partial requirements customer of BPA:

Utility Y - before renewables purchase

BPA purchased power costs	$ 59 million
Other utility costs	$147 million
Total costs	$206 million
BPA purchased kWh	2.2 billion kWh
Annual kWh sales	6.2 billion kWh
Average retail rate	33 mills/kWh

Assume that the cost of BPA power has increased by 1.5 mills/kWh and BPA purchased power cost has increased by about $3,300,000. The results would be as follows:

Utility Y - after renewables purchase

BPA purchased power costs	$62,300,000
Other utility costs	$147 million
Total costs	$209,300,000
BPA purchased kWh	2.2 billion kWh
Annual kWh sales	6.2 billion kWh
Average retail rate	33.75 mills/kWh

The increase in the average cost of power at Utility Y would be about 0.75 mills/kWh, or about 2.25 percent.

For other BPA customers the rate effect to ultimate customers could be greater or less depending on the ratio of BPA power costs to total costs.

Environmental Impacts

The environmental effect of this module would depend on the incremental amount of renewable resources acquired in each alternative, which would vary in this module from 300 aMW (in BPA Influence, Market-Driven, and Maximize Financial Returns) to 380 aMW (in Short-Term Marketing). It is likely that the additional renewable resources would replace or reduce the acquisition of CTs and/or cogeneration. The resulting environmental impact would be a reduction in the air quality, water use, and land use impacts of these resource types (identified on a per-megawatt basis in Table 4.3-1, Typical Environmental Impacts From Power Generation and Transmission, and figure 4.5-1). This overall positive environmental impact would be offset to a slight extent by the greater land use impacts of renewables. (As shown in table 4.3-1, renewable resources tend to be fairly land-intensive.)

As an illustrative example, if BPA (and therefore, the region) were to acquire an additional 300 aMW (180 aMW wind and 120 aMW geothermal) in the Market-Driven BPA alternative, land use impacts would increase approximately 6.5 percent (from 15,000 hectares to 16,000 hectares), while the air quality impacts of new and existing thermal generation (as expressed in terms of environmental costs) would decline approximately 2 percent (from $332 to $325 million).

4.5.4.4 "Green" Firm Power (CR-4)

Module Description

BPA would offer, as an optional power product, an amount of Tier 2 power supported by the acquisition of conservation and renewable resources that would not otherwise be acquired as a part of Tier 2 new resource additions. The amount of "Green" Firm Power that BPA would offer would depend on the willingness of BPA customers to commit to purchase the output for the economic life of the resources. BPA would develop a proposal that describes the resource pool composition and cost. BPA customers would respond indicating the quantity of the "Green" Firm Power. Contracts would be for 20 to 30 years depending on the type of resources included in the pool.

For purposes of this module, BPA was assumed to acquire up to an additional 80 aMW of renewable resources by 2002. The resources would be a mix of 60 percent wind and 40 percent geothermal. The nominal cost in 2002 of wind resources is projected to be between 60 and 75 mills/kWh, and the cost of geothermal resources is projected to be between 80 and 100 mills/kWh. The melded cost in 2002 of this pool is estimated to be about 75 mills/kWh.

Effects of Module on Alternatives

By developing a "Green" Firm Power resource pool, BPA would not acquire a like amount of CTs and/or power purchases. However, "Green" Firm Power could help reduce the load BPA loses to other suppliers by offering its customers a more environmentally benign resource pool that leads utilities who are interested in such resources to place load on BPA.

This module would be revenue-neutral to BPA because BPA would only acquire renewable resources in an amount equal to the commitments made by its customers for the "Green" Firm Power.

The effect on bills of ultimate consumers is uncertain for a variety of reasons. Retail rate effects would depend on how much of the "Green" Firm Power the utility acquired, the ratio of BPA purchased power costs to total costs, and the total kWh sales for the utility. For example, if a full requirements customer committed to purchase from the "Green" Firm Power and BPA purchased power costs represented 50 percent of its total costs, then a 10 percent increase in power costs would lead to a 5 percent increase in the utilities' total costs.

The following example shows the retail rate effect for ultimate consumers at a hypothetical utility that is a full requirements customer of BPA:

Utility X - before “Green” Firm Power purchase

BPA purchased power costs	$10 million
Other utility costs	$11 million
Total costs	$21 million
Annual kWh sales	375 million kWh
Average retail rate	56 mills/kWh

Assume that “Green” Firm Power made up 10 percent of Utility X's BPA purchases and that the cost of the “Green” Firm Power is about three times the standard BPA rate, or 75 mills/kWh. The results would be as follows:

Utility X - after “Green” Firm Power purchase

BPA purchased power costs	$11.9 million
Other utility costs	$11 million
Total costs	$22.9 million
Annual kWh sales	375 million kWh
Average retail rate	61 mills/kWh

The increase in the average cost of power at Utility X would be 5 mills, or 9 percent.

The second example shows the retail rate effect for ultimate consumers at a hypothetical utility that is a partial requirements customer of BPA:

Utility Y - before “Green” Firm Power purchase

BPA purchased power costs	$ 59 million
Other utility costs	$147 million
Total costs	$206 million
BPA purchased kWh	2.2 billion
Annual kWh sales	6.2 billion kWh
Average retail rate	33 mills/kWh

Assume that “Green” Firm Power made up 10 percent of utility Y's BPA purchases and that the cost of the “Green” Firm Power is about three times the standard BPA rate, or 75 mills/kWh. The results would be as follows:

Utility Y - after “Green” Firm Power purchase

BPA purchased power costs	$ 70 million
Other utility costs	$147 million
Total costs	$217 million
BPA purchased kWh	2.2 billion
Annual kWh sales	6.2 billion kWh
Average retail rate	35 mills/kWh

The increase in the average cost of power at Utility Y would be 2 mills/kWh, or 6 percent.

For other BPA customers the rate effect to ultimate customers could be more or less depending on how much “Green” Firm Power a utility purchased, and the ratio of BPA power costs to total costs.

Environmental Impacts

As in the other renewable resource modules, the primary effects of this module would be to decrease the impacts associated with CTs (air quality impacts and water and land use) and to increase the impacts associated with renewable resources (primarily land use). The magnitude of these changes would depend on the amount of renewable resources acquired and the amount of CT operations displaced.

As an illustrative example, if in the Short-Term Marketing alternative the region acquired an additional 80 aMW of renewable resources (for example, 48 aMW of wind and 32 aMW of geothermal), total land use impacts of new resources would increase slightly, while total air quality impacts of new and existing thermal generating resources (as measured in terms of the environmental costs shown in table 4.4-20) would decrease approximately 0.5 percent (from $339 million to $332 million).

4.6 Cumulative Impacts

This EIS evaluates the impacts of BPA actions on both BPA and on the region as a whole. The alternatives involve actions that are likely to contribute to cumulative environmental impacts. The development and operation of generation resources and transmission could impact land use, air, water, and fish and wildlife. These impacts in and of themselves may not be major, but may be significant when added to the impacts of other actions. The cumulative impacts of resource development and operation are addressed in the Resource Programs Final EIS (DOE, February 1993), which provides information about the cumulative environmental impacts of adding different sets of conservation and generation resources to the existing power system.

Alternative operations of the hydroelectric system could contribute to cumulative impacts on sensitive anadromous and resident fish stocks; however, future hydroelectric system operations will occur within the parameters established by the System Operations Review (SOR).

4.7 Relationship Between Short-Term Uses of the Environment and the Maintenance and Enhancement of Long-Term Productivity

All of the alternatives evaluated in this EIS involve the construction and operation of generation and transmission resources, and therefore require both long- and short-term uses of the environment. In the short-term, construction of generation and transmission resources would cause noise, soil compaction and erosion, the potential for water quality degradation, and degradation of air quality. Many of these short-term construction impacts can be substantially mitigated. In the longer term, there could be impacts on air quality, altered land uses, reduced water quality, and contributions to global warming.

Both the short-term and long-term uses of the environment will, however, have a beneficial effect on long-term productivity. Delivering cost-effective electric energy in a way that minimizes adverse effects on the environment will help maintain and enhance the productivity of the PNW and its economy.

4.8 Irreversible or Irretrievable Commitments of Resources

The acquisition and operation of new generation and transmission resources (an element of all alternatives) would require irreversible and irretrievable commitments of resources. Those alternatives with larger amounts of conservation acquisition (e.g., BPA Influence, Status Quo, and Market-Driven alternatives) would have fewer such commitments of resources, but even they would require substantial commitments associated with new generation and transmission facilities.

4.9 Key Factors That May Limit Implementation

The likelihood that any alternative could be implemented, would serve its projected load, and would meet its other objectives will depend on a number of key determinants. For example, if an alternative would require statutory changes, its likelihood of success is less than an alternative that could be implemented without such changes. This section seeks to indicate, in a general way, the relative likelihood of success among the six alternatives (see figure 2.7-1).

The analysis in this section is based on BPA's informed judgment about factors like legislative process or regulatory influences, market conditions, financial constraints, and other factors. It is intended to rank the alternatives against each other; it does not seek to precisely indicate how much more or less likely each alternative may be.

4.9.1 Factors Affecting All Alternatives

These factors affect the probability of success for all of the alternatives. First, BPA's fixed cost ratio of 80 to 85 percent, compared to an industry average of 50 to 60 percent, creates a risk that BPA would be unable to implement any of the alternatives successfully over the long term. As described in the Business Plan, because BPA must operate under a higher fixed cost ratio, BPA may be less flexible and less able to absorb costs than its competitors. This factor may result in a higher risk of BPA losing load compared to its competitors.

The second factor affecting all of the alternatives is the lack of regional consensus regarding BPA's fish and wildlife responsibilities and how BPA will meet energy conservation targets. One significant reason fish and wildlife and conservation issues are contentious is that both issues lack scientific or analytic precision for determining success, particularly in the near term. As a result, it will be difficult for the region to achieve a clear consensus on program direction or individual project designs for both programs. Without consensus, costs would likely rise.

A third factor is the continuing and dramatic decline in the market price for electric energy in the PNW. If prices reach a level significantly below BPA's costs and remain there for the long term, BPA will have difficulty achieving its missions under any alternative, because very low prices would not provide enough revenue to enable BPA to sustain its mandated activities.

All of these factors would decrease BPA's ability to succeed across all the alternatives.

4.9.2 Status Quo Alternative

The probability of continuing to implement the Status Quo alternative successfully is decreased by at least three factors. First, because this alternative does not include any explicit cost control mechanisms, BPA would have a difficult time instilling confidence in its customers that BPA would, over both the short and long term, control its costs. Second, lacking cost controls, BPA would also face a greater potential for rate increases. These rate increases would encourage customers to shift loads away from BPA. Third, if BPA continued to ignore market changes and signals, it might continue to develop unnecessary new resources when there is no corresponding increase in BPA load. This would result in increased costs and further erosion of BPA's low-cost hydro advantage, increasing rates and adding to power surpluses. For these reasons, the continued implementation of this alternative would reduce its effectiveness and lead to changes in BPA's policies or legislative authorities.

4.9.3 BPA Influence Alternative

The probability of successfully implementing the BPA Influence alternative is decreased by its high costs and requirements that would likely be borne by BPA's customers. Since this alternative would continue BPA's full funding of conservation target efforts, it would tend to increase BPA rates. More importantly, because this alternative also seeks to increase BPA's efforts to induce customers to implement the Council's F&W Program and Power Plan through conditions of service and other requirements, it might decrease the attractiveness of BPA services to many customers. High costs coupled with increased conditions of service (the "hassle factor") would reduce the potential effectiveness of this alternative. Customers would go to non-BPA suppliers for services previously provided by BPA, causing further BPA load reductions and increased rates, and lessening BPA's ability under this alternative to implement the Council's F&W Program or Power Plan.

4.9.4 Market-Driven Alternative

The probability of successfully implementing this alternative is higher than the other alternatives because the Market-Driven approach has the greatest potential to overcome barriers to implementation through improved customer relations, and focused efforts to control and stabilize costs. The chance of success could be reduced by BPA's inability to establish successful marketing practices to achieve business results, causing customers to seek non-BPA suppliers and reducing BPA loads. In addition, lack of consensus on fish and wildlife and conservation reinvention could jeopardize constituent support for the overall alternative. Changes from past practices that place costs with specific customer groups that were formerly spread over the system as a whole could alienate the customers bearing those costs and jeopardize implementation of the Market-Driven alternative.

4.9.5 Maximize Financial Returns Alternative

The probability of successfully implementing the Maximize Financial Returns alternative is small because BPA would need revisions to the Northwest Power Act and other statutes to achieve the key elements of the alternative. This alternative would require authority for BPA to recover revenues in excess of its costs, limit conservation investment, and transfer fish and wildlife responsibility to other entities. Despite the desire by different interests to alter various provisions of the Act, regional consensus regarding any specific amendments is necessary. In addition, the changes in BPA's business strategy to implement the Maximize Financial Returns alternative would likely be viewed as a departure from BPA's historical role of providing benefits to the region, and would probably alienate both customers and constituent groups.

4.9.6 Minimal BPA Alternative

Like the Maximize Financial Returns alternative, the probability of successfully implementing the Minimal BPA alternative is greatly reduced by the need for revisions to the Northwest Power Act and other statutes. Since under this alternative BPA would not accept load growth or increased transmission responsibility, would limit conservation investments, and would transfer fish and wildlife responsibility to other entities, changes in statutes would be required. As in the Maximize Financial Returns alternative above, despite the desire by some interests to alter various provisions of the Act, regional consensus regarding any specific amendments is necessary and does not appear probable. The significant curtailment of BPA's actions to provide benefits to the region could either create opposition to this approach, or engender proposals to eliminate BPA altogether and sell its assets.

4.9.7 Short-Term Marketing Alternative

This alternative would only provide sustainable BPA marketing if the bulk of BPA's customers would accept a short-term approach to BPA marketing. The chief limitation in this alternative is that it fails to meet the needs of those customers who desire long-term service and stability of power supplies. Confidence of environmental constituents and the remaining customers in BPA's ability to achieve the fish and wildlife and conservation results would be low due to the lack of certainty about BPA maintaining customer load, and limitations in investments for short-term paybacks.

4.9.8 Comparison of Alternatives

The Market-Driven alternative has the highest probability of successful implementation because it promotes customer confidence and constituent support for the goals BPA establishes for controlling costs and achieving its regional fish and wildlife and conservation missions.

The BPA Influence alternative has the second highest probability of successful implementation, but is lower than the Market-Driven alternative, because the BPA Influence alternative relies on BPA customers to accept restrictive conditions of service and higher costs during a time when the electric utility industry is becoming increasingly competitive.

The Short-Term Marketing alternative has less chance of successful implementation than the Market-Driven and BPA Influence alternatives because utilities would need to accept a high level of uncertainty about long-term costs. This is especially difficult in a time when the electric utility industry is becoming more and more competitive and utilities have more resource options. This would decrease the confidence of environmental constituents and the remaining customers in BPA achieving progress toward the regional fish and wildlife and conservation goals.

The Status Quo, Maximize Financial Returns, and Minimal BPA alternatives have the lowest probability of successful implementation. Continuing the Status Quo has a low probability because it lacks BPA cost controls, clearly identified business results, and stable rates. Maximize Financial Returns and Minimal BPA have little chance of successful implementation due to the requirement for legislative changes and significant changes in BPA's mission.